DELPHI ENERGY CORP. / annual report /06

long life reserves
multi-zone prospects
high netback production
strong hedging program
high impact exploration

the big picture

inventory of opportunities
natural gas focus
conventional prospects
resource development
experienced personnel
per share growth

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Corporate Profile

DELPHI ENERGY CORP. ("DELPHI" OR "THE COMPANY") FOCUSED ON THE BIG PICTURE IN 2006, BUILDING A FOUNDATION FOR THE FUTURE THROUGH CAPITAL EXPENDITURES AT BIGSTONE IN NORTH WEST ALBERTA AND BIGFOOT IN NORTH EAST BRITISH COLUMBIA. THE COMPANY INVESTED A RECORD $165 MILLION DURING THE YEAR ON ONE-TIME INFRASTRUCTURE SUCH AS GAS GATHERING FACILITIES AS WELL AS DEVELOPMENT DRILLING, WELL WORKOVERS AND REACTIVATIONS.

The Company's capital expenditures and drilling success helped increase its production, reserves, funds flow and net earnings over the year and position Delphi for measured growth in 2007. The Company has a large inventory of development opportunities complemented by a high-impact exploration program.

Delphi sets itself apart from its peers by its high quality multi-zone natural gas focused asset base, its long-term organic growth potential with more than five years of defined and repeatable opportunities, its history of per share value creation and its share price that is currently at 2.1 times projected 2007 cash flow and 50 percent of the Company's estimated net asset value per share.

Based in Calgary, Alberta, Delphi started as a private oil and natural gas explorer and producer in January 2003, went public on the TSX Venture Exchange in June 2003 after the merger of Rise Energy Ltd. and DT Energy Ltd. and graduated to the Toronto Stock Exchange in August 2004. Delphi trades under the symbol DEE.

highlights /1

Years Ended December 31	*2006*	*2005*
Financial Highlights		
(CDN$ thousands except per boe and per share amounts)		
Gross petroleum and natural gas sales	94,189	80,880
Per boe	49.36	52.48
Funds from operations	49,551	40,212
Per boe	25.97	26.09
Per share – Basic	0.85	0.80
– Diluted	0.84	0.79
Net earnings (loss)	6,903	6,677
Per boe	3.62	4.32
Per share – Basic	0.12	0.13
– Diluted	0.12	0.13
Capital costs	165,352	112,468
Proceeds on dispositions	(34,918)	(5,862)
Net capital	130,434	106,606
Debt plus working capital deficit	118,178	60,375
Total assets	326,668	244,666
Shares outstanding (thousands)		
Basic	60,663	55,254
Diluted	64,892	57,883

Years Ended December 31	*2006*	*2005*
Operating Highlights		
Average Daily Production		
Natural gas (mcf/d)	25,706	19,848
Percentage of total production	82%	78%
Oil and natural gas liquids (bbl/d)	944	913
Percentage of total production	18%	22%
Total (boe/d)	5,228	4,221
Realized selling prices		
Natural gas ($/mcf)	8.03	9.20
Oil and natural gas liquids ($/bbl)	54.67	42.78
Total oil equivalent ($/boe)	49.36	52.48
Wells drilled		
Gross	52.0	45.0
Net	21.7	22.6
Undeveloped land		
Gross acres	274,581	272,491
Net acres	86,062	51,836
Average working interest	31%	19%
Proved plus probable reserves (P+P)		
Natural gas (mmcf)	85,116	69,081
Oil and natural gas liquids (mbbls)	3,125	2,911
Total oil equivalent (mboe)	17,311	14,424
Finding and development costs (P+P)($/boe)	32.04	17.86
Reserve life index (P+P)(years)	9.1	9.4

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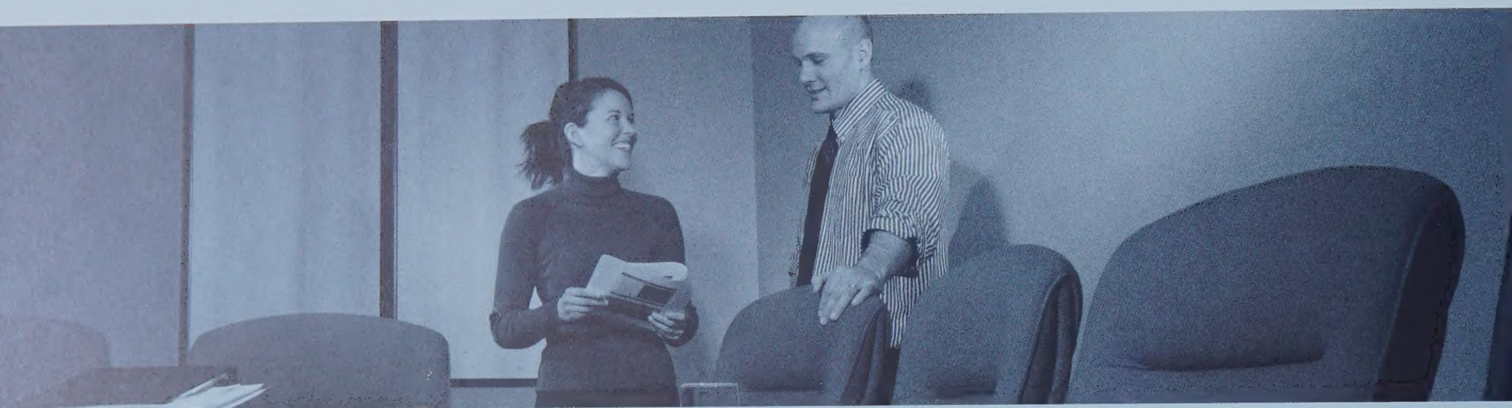


production (boe/d)

production (boe/d per million shares)

reserves (mboe)

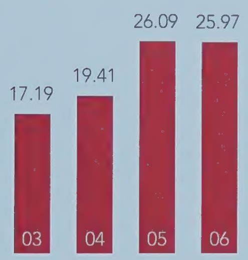
reserves (boe per thousand shares)

natural gas prices ($/mcf)

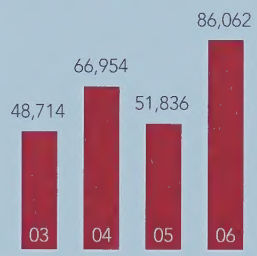
operating costs ($/boe)

/3

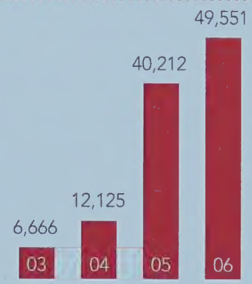
cash netbacks ($/boe)



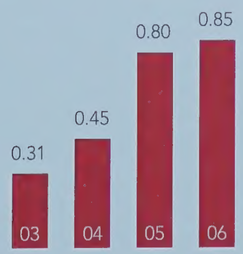
undeveloped land (acres)



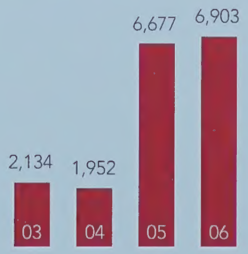
cash flow (CDN$ thousands)



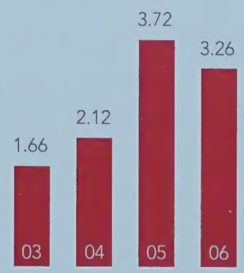
cash flow per share



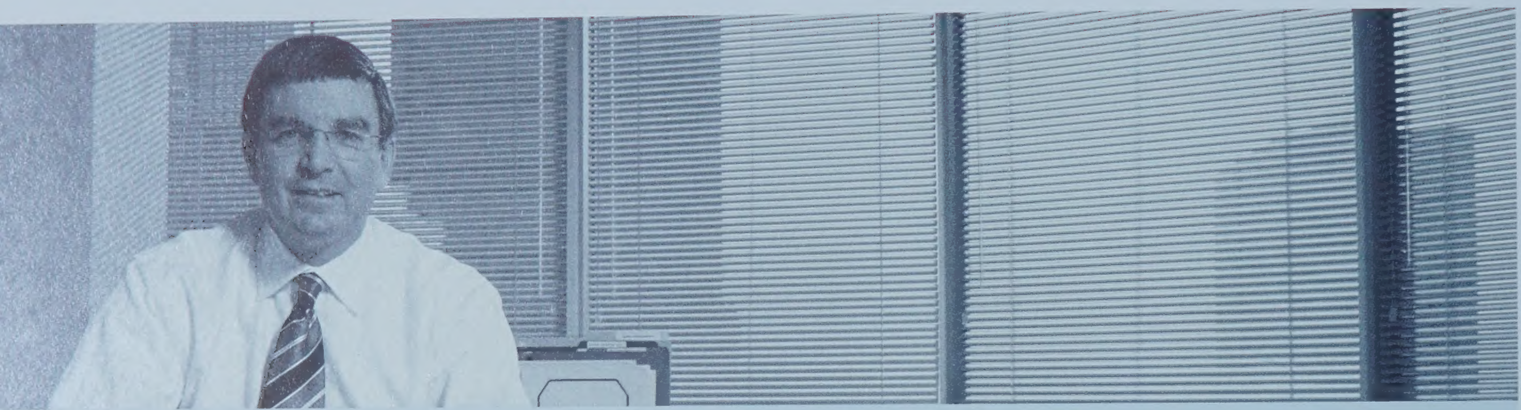
net earnings (CDN$ thousands)



net asset value ($/share)



4\ message to shareholders



Delphi grew through the drill bit in 2006. The company's average production increased 24 percent to 5,228 barrels of oil equivalent per day, proved plus probable reserves increased 20 percent to 17.3 million barrels of oil equivalent, funds flow increased 23 percent to $49.6 million and net earnings increased three percent to $6.9 million.

Our growth resulted from continued success through the drill bit. Delphi spent $165 million to drill 52 wells (21.7 net) in 2006 with a 90 percent success rate. All but four of these wells were drilled during the first four months of the year. This compares favourably with the 45 wells (22.6 net) drilled in 2005, but is much lower than the 72 wells expected to be drilled during the year.

Successful drilling at Bigstone in North West Alberta and Bigfoot in North East British Columbia helped increase the Company's production, reserves, funds flow and net earnings over the past year and establish a solid foundation for the future. In addition, significant capital was deployed during 2006 constructing one-time gas gathering infrastructure in both of these areas in preparation for future development drilling.

Although the pace of growth in 2006 fell short of expectations, the results best represent a mid-mountain plateau rather than the summit in our long term growth strategy. At Bigfoot, a successful winter drilling program was over-shadowed by significantly higher than anticipated costs, primarily for the infrastructure, resulting in fewer wells drilled at Bigfoot and limiting our financial flexibility to spend capital elsewhere throughout the remainder of 2006. In addition, the initial flush production from several wells successfully drilled late in 2005 experienced higher than expected decline rates during the first half of the year. Although decline profiles from these wells continue to moderate to a more typical 12 percent to 15 percent per year, the subsequent production shortfall was not replaced due to a significantly curtailed capital program during the second half of the year, drilling only four of 17 wells planned. The combination of these factors contributed to lower than anticipated production and funds flow, increased concern regarding the Company's debt levels and discontent in the market, resulting in a growing gap between the Company's strong fundamentals and a weak share price.

In addition to the Company's growth through the drill bit, Delphi has successfully employed an acquisition strategy that has included the $57 million acquisition of a private company at the end of 2004, the $51.3 million acquisition of 24,000 acres of natural gas properties at Bigstone at the beginning of 2005 and the opportunity captured at Bigfoot at the end of 2005. The Bigfoot farm-in agreement with a senior producer called for Delphi to pay 90 percent of the costs to earn a 50 percent working interest in the area's wells. After drilling 16 wells in Bigfoot, the Company has satisfied the terms of the agreement and will participate on a 50/50 basis going forward.

These successful growth initiatives have been financed through a combination of funds flow from operations, new equity, non-core asset dispositions, and incremental bank debt. The quality of the producing assets offer a high netback funds flow stream as well as a reliable borrowing base. A strategic

24% increase in average production per day

commodity hedging program protects the funds flow stream from commodity price volatility. Delphi has approximately 55 percent of its natural gas production hedged at a minimum price of almost $9.00 per mcf through to March 2008. This compares favourably to both the 2006 AECO average price of $6.55 per mcf and the 2005 AECO average price of $8.81 per mcf.

Over the past four years through the many successes and only a few disappointments around the above growth initiatives, the debt to funds flow ratio has fluctuated from a high of 3.0 in the first quarter of 2005 to a low of 1.0 at the end of 2005, increasing again to a current ratio of 2.4 at the end of 2006. The Company has set its growth plans incorporating a desired downward trending debt to funds flow ratio of 1.7 at the end of 2007 and back to 1.0 by the end of 2008. The Company will continue to use leverage respectfully, balancing the cost of capital and risk to facilitate, not limit, our growth.

Operational Review

Average production for the year of 5,228 boe/d represents a 24 percent increase over the 4,221 boe/d produced in 2005. Natural gas and NGL production volumes accounted for 91 percent of Delphi's production in 2006 compared with 85 percent in 2005.

During the year, the Company drilled a total of 52 (21.7 net) wells, with a success rate of 90 percent. The 2006 drilling program resulted in 19.0 net natural gas wells, 0.6 net oil wells and 2.1 net dry holes. The Company pursued only a limited drilling program in the second half of 2006. The successful 2006 development and exploration drilling program resulted in significant reserves growth for the Company. Proved natural gas reserves increased 16 percent with net additions of 17.3 billion cubic feet (bcf) and proved plus probable natural gas reserves increased 23 percent with net additions of 25.4 bcf. Total additions on a proved reserves basis were 2.9 million boe and total additions on a proved plus probable reserves basis were 4.8 million boe. Total proved reserves increased nine percent to 11.4 million boe and proved plus probable reserves increased 20 percent to 17.3 million boe. The reserve additions for the year resulted in a reserve replacement ratio of 2.5 times 2006 production of 1.9 million boe.

Finding and development costs for 2006 on a proved plus probable basis were $32.04 per boe, including future development capital. This compares with our three-year average finding and development costs of $21.46 per boe on the same basis. At Bigfoot, Delphi contributed 90 percent of the capital to earn a 50 percent working interest in the property, spending $91.4 million, of which 40 percent was spent on major one-time infrastructure and seismic rather than on drilling activities that have an immediate production, funds flow and reserves impact. Finding and development costs in 2006 for Delphi at Bigfoot were approximately $25.40 per boe, after giving effect to the earning terms. This compares to approximately $14.00 per boe on a gross basis which better represents expected efficiencies on a go-forward basis.

Financial Review

Funds from operations for 2006 were $49.6 million ($0.85 per share), an increase of 23 percent over the prior year. Delphi achieved this funds flow through a combination of higher than benchmark realized natural gas prices resulting from its strategic risk management program, an improved cost structure and increased production compared to the previous year. The risk management program resulted in hedging gains of $10.5 million increasing the Company's average realized natural gas price by $1.12 per mcf, 17 percent higher than the benchmark AECO price in 2006. Operating costs per boe were reduced to $8.29 per boe from $8.46 in 2005 despite a high inflationary environment for oilfield services throughout most of the year. Cash netbacks were virtually unchanged at $25.97 per boe compared to $26.09 per boe from the previous year. Net earnings for the year were $6.9 million ($0.12 per share) compared to $6.7 million ($0.13 per share) in 2005.

3% increase in funds flow to 49.6 million, while AECO nchmark prices decreased 26

In 2006, Delphi incurred record total capital expenditures of $165.4 million, with 55 percent of the capital being incurred at Bigfoot in North East British Columbia to satisfy its obligation to earn a 50 percent working interest in 19 wells, non-recurring infrastructure costs and 118 sections (75,520 acres) of land. The majority of the remaining capital was incurred at Bigstone, Alberta through the drilling of six gross (4.2 net) wells and expansion of the Company's infrastructure in the area to provide for development of the west block of the Company's lands in the area. The capital program was financed through proceeds on disposition of non-core low working interest properties, funds from operations, issuance of flow-through common shares and utilization of the Company's credit facilities with its lenders.

Outlook

The successes, challenges, and business environment of 2006 set the stage for measured growth expectations in 2007. The Company continues to plan and execute its capital spending within near term funds flow expectations as a result of the uncertain and volatile natural gas price environment. Delphi maintains the view that natural gas supply and demand fundamentals will gradually improve during 2007 providing greater clarity and upside to natural gas prices into 2008. The Company expects to spend a greater portion of its capital program during the second half of 2007 providing significant growth potential into 2008 as the capital program further unlocks the undeveloped value in Bigstone, Bigfoot and other core assets. Natural gas price clarity and moderating equipment and service costs are catalysts to a more sustainable growth environment. For Delphi, with one-time infrastructure capital completed, these catalysts are only a bonus, as future capital efficiencies are already forecast to improve significantly with a much greater percentage of the capital focused on drilling.

Delphi expects to spend its estimated funds flow of $45 to $50 million in 2007 to increase its average production to between 5,200 to 5,400 boe/d and exit the year producing approximately 5,700 boe/d. Approximately 60 percent of Delphi's proved non-producing reserves are expected to be on production in the second quarter of 2007, including our exploration discovery at Tower Creek, Alberta. Initial production rates at Tower Creek are projected to be approximately 500 to 600 boe/d net to Delphi and the Company expects to drill a second exploration test in the area after spring break-up. Additional production volumes are expected to come on stream early in the second quarter as the winter drilling program concludes.

Delphi continues to trade at a significant discount to its net asset value per share estimated to be $3.26 (discounted eight percent before tax) based on our December 31, 2006 reserves as evaluated by GLJ Petroleum Consultants Ltd. and reflects only a portion of the undeveloped growth potential and value within the Company. The Company is committed to regaining market confidence through a successful 2007 capital program delivering on and exceeding growth expectations.

Delphi has a significant inventory of defined and repeatable prospects. The Company has the producing assets, prospects and financial resources to deliver long-term organic growth. Delphi continues to add to its inventory of opportunities through strategic industry relationships. Thanks to these distinguishing characteristics and a talented team, I believe the Company will quickly return to its track record of 20 to 25 percent annual growth. I would like to express my gratitude to our loyal shareholders for looking past short-term natural gas price pressures, operational challenges and stock market fluctuations in order to keep an eye on the big picture. I'm confident this patience will be rewarded.

On behalf of the Board,

David Reid

David J. Reid
President and Chief Executive Officer
March 13, 2007

operations review /7

achieved $10.5 million in hedging gains equivalent to $1.12 per mcf

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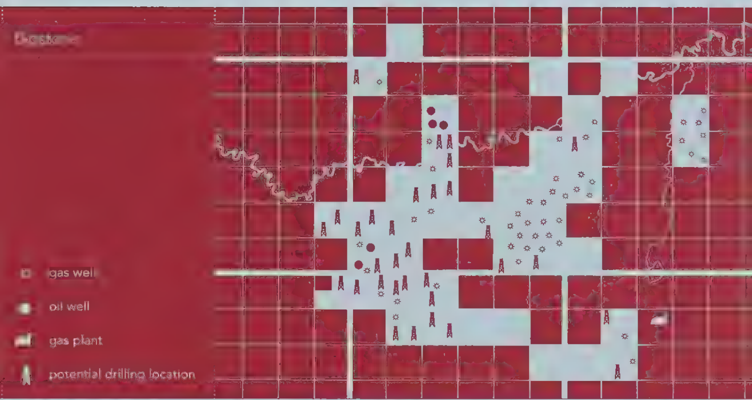
During 2006, Delphi's production averaged 5,228 barrels of oil equivalent per day, an increase of 24 percent from the 2005 average of 4,221 boe/d. In 2006, Delphi participated in drilling 52 wells (21.7 net), achieving a net success rate of 90 percent. Total capital expenditures were $165.4 million while proceeds on the disposition of assets were $34.9 million. Approximately 55 percent of all capital was incurred on the Company's joint venture at Bigfoot in North East British Columbia and 17 percent was spent at Bigstone in North West Alberta.

Delphi is anticipating a 2007 capital budget in the range of $45 to $50 million, primarily based on the generation of funds flow from operations. Approximately 75 to 80 percent of the budget will be spent on low/medium risk development projects, primarily on properties in North East British Columbia and North West Alberta. Approximately 20 to 25 percent will be spent on high-impact exploration projects. As a result of the contemplated budget, Delphi expects to drill 20 to 25 wells in 2007 at an average working interest of approximately 60 percent.

over 100 drilling locations identified on company lands



north west alberta

Bigstone

The Bigstone area in North West Alberta is located 150 kilometres southeast of Grande Prairie. Delphi produced 2,524 boe/d in 2006, consisting of 12,300 mcf/d of natural gas and 470 bbl/d of natural gas liquids. Bigstone production is primarily from the Cretaceous Dunvegan sands, however deeper drilling into multiple intervals of the Bullhead group as well as shallower completions in the Cardium has also proven successful. Delphi operates in excess of 95 percent of its production in the area and has an undeveloped land base of approximately 4,000 net acres. The Corporation also has a 29 percent working interest in an 80 mmcf/d natural gas plant and associated gathering system. The ownership of infrastructure is a key contributor to low operating costs for the area which translates into premium netbacks per boe.

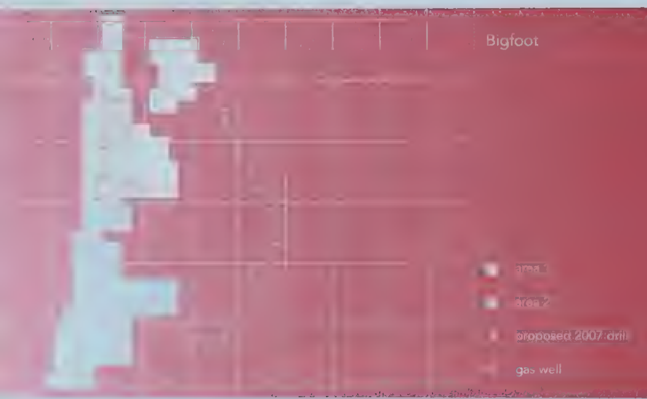
Well control and sub-surface mapping indicates the undeveloped lands are highly prospective for multiple zones similar to the producing intervals in Bigstone proper. In 2006, the Corporation drilled 10 wells (5.3 net), primarily on these western lands, resulting in a light oil discovery and continued success in the Gething and Dunvegan formations. This success continues to generate additional drilling opportunities and the Company anticipates drilling 8 to 10 wells in 2007 at an average working interest of approximately 50 percent. The gas wells are characterized by initial average production rates of 1,500 mcf/d (approximately 250 boe/d) with individual well rates as high as 6,000 mcf/d (approximately 1,000 boe/d). First year decline rates are on the order of 40 to 50 percent moderating to 12 to 15 percent over the life of the reserves. The high initial production rates and netbacks are instrumental in recouping invested capital in less than two years and the future low decline rates provide for a stable and predictable cash flow stream. The current inventory of drilling prospects will provide for sustained drilling over the next three to five years.

north east british columbia

Bigfoot

The Bigfoot area in North East British Columbia is located 80 kilometres southeast of Fort Nelson. First production was initiated in April 2006, and averaged 551 boe/d net (97 percent natural gas) to Delphi over the eight months from April to December. Currently all Bigfoot production is from the Jean Marie, however there is significant secondary potential in the Cretaceous, Triassic, Mississippian, and Devonian formations. The Jean Marie wells are characterized by very strong initial flush production rates as high as 2-3 mmcf/d declining over 50 percent in the first year with a typical decline rate of less than 10 percent over the life of the reserves.

than 80% natural gas and reserves



vember 2005, Delphi announced a farm-in agreement with a senior industry producer to jointly a natural gas resource play in the Bigfoot area of North East British Columbia. The agreement Delphi an opportunity to earn a 50 percent working interest in excess of 200 sections of land, rea of Mutual Interest ("AMI") being established which covers more than 200 additional sections nd. The farm-in involved the Jean Marie trend which is considered one of the largest regional plays scovered in the Western Canada Sedimentary Basin in the past decade. To date, in excess of 1,100 been drilled and completed in the Jean Marie formation. Current production and cumulative for the trend are in excess of 465 mmcf/d and 1.1 trillion cubic feet of gas, respectively.

reement divided the lands into a northern block ("Area 1") consisting of 118 sections of land and a n block ("Area 2") consisting of 92 sections of land. The earning commitment on the northern half joint venture lands involved the drilling of 19 wells and the tie-in of five existing productive wells, ion of a 30 kilometre, 12-inch natural gas transmission pipeline to transport the natural gas from the an existing processing facility in the Greater Sierra area owned and operated by the joint er and construction of a 54 kilometre all-season road providing access to the undeveloped earning provision also included the acquisition of approximately 200 square kilometres of 3D Area 2. The Company was required to pay 90 percent of the capital expenditures to earn a 50 g interest in the lands and infrastructure.

an shortly after signing the agreement with the mobilization of construction equipment, as ditions allowed, to build winter roads for drilling and the construction of key infrastructure. By e 2005/2006 winter season, the all-season road from the north end to the south end of Area ompleted and the transmission pipeline had been installed and connected to the operator's rocessing facilities in the Greater Sierra area. The Company incurred expenditures of $81.4 Area 1, consisting of $30 million of non-recurring infrastructure costs which will provide year- e development on the lands in Area 1.

e earning phase for Area 1 complete and the overall project metrics for the Jean Marie formation ck, the Company has the opportunity to develop a long life asset with a significant drilling inventory acterized by low risk and low finding and development costs. Based on the initial development se, independently evaluated estimates of proved plus probable reserves are 3.4 million barrels of oil equivalent net to Delphi. The indicated reserves, as evaluated by GLJ Petroleum Consultants Ltd., are based on the 21 wells drilled to date and seven additional locations which develops less than 10 percent of the 118 gross sections (50 percent net to Delphi). Joint venture earning terms and cost overruns primarily associated with the infrastructure contributed to an all in finding and development cost of approximately $25.40 per boe. Future finding and development costs are estimated to be approximately $14.00 per boe now that the necessary infrastructure is in place to accommodate the significant development potential of this asset. Based on 2006 production rates, the Bigfoot asset has a reserve life index in excess of 15 years for the proven plus probable reserves.

Delphi also completed the acquisition of 3D seismic over 65,000 gross acres in Area 2. The data, costing approximately $10 million, has been processed and is of very high quality with mapping suggesting Area 2 is equally as prospective as Area 1. As part of the agreement, Delphi had an option to enter into a similar type of earning commitment on Area 2, during the winter of 2007/2008, to earn a 50 percent working interest on these lands. Due to the high costs of services experienced on Area 1 and the volatility of natural gas prices experienced over the past six months, the Company chose not to exercise its option on these lands under the original terms contemplated. The operator has significantly curtailed the Area 2 capital program, indicating there may be an opportunity to farm-in on these lands in the future.

Other properties

The Company's remaining assets in North East British Columbia produce from various fields and formations; including the shallow Cretaceous Bluesky at Kotcho, the deeper Permian Mattson at Windlfower and Mississippian Debolt at Helmet, and the deep Devonian Jean Marie and Slave Point carbonates at Helmet North and Missile.

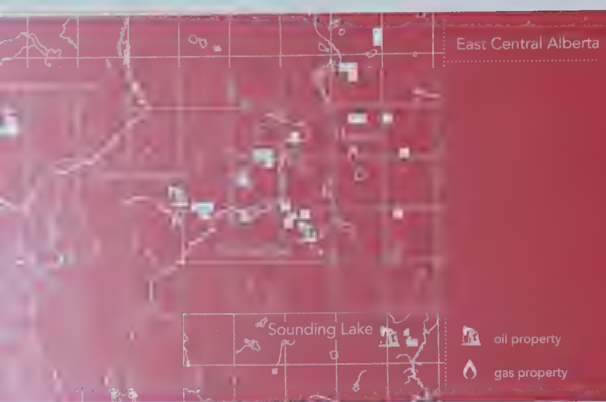
Early in 2006, the Corporation participated in drilling 7 wells (3.4 net) on these properties and net production averaged approximately 1,075 boe/d in 2006. At Clarke Lake and Bullmoose, Delphi divested its small, non-operated working interest for total proceeds of $16.3 million. At Peggo, Delphi acquired 2,900 acres of undeveloped land, a 100 percent working interest in 13 kilometres of a sour gas transmission pipeline and a 50 percent working interest in a 30 mmcf/d processing facility.

Currently, Delphi has access to 19,000 net undeveloped acres at operated and non-operated working interests that vary from one to 100 percent. While the 2006/2007 winter program has been focused on remedial well work and optimization projects associated with the drilling program from earlier in the year, the 2007/2008 winter program will see a return to the low risk, predictable drilling of infill and step-out locations.

north west alberta

Fontas

At Fontas, Alberta, located 300 kilometres north of Grande Prairie, Delphi produced approximately 470 boe/d in 2006, consisting of 2,800 mcf/d gas through a company owned facility. Production is primarily from the Mississippian Debolt/Elkton and the Cretaceous Detrital formations which are typically less than 800 metres in depth. A combination of sub-surface data, 2D and 3D seismic data is utilized to identify low-risk development wells in the existing pools and medium-risk step-out wells that create development opportunities for the following winter drilling season. The majority of the drilling and rework activity occurs in the



vinter months, usually the end of December through the middle of March, due to local surface conditions. At Fontas, Delphi has a 20 percent working interest in a contiguous land base in excess of 160,000 acres, the gathering system and a 40 mmcf/d processing facility that is tied into the Nova pipeline system.

During the winter of 2005/2006, Delphi participated in drilling 13 wells (2.6 net) at Fontas. Nine of the wells ere successfully completed as gas wells and tied-in, 3 wells were suspended pending further evaluation 1 well was abandoned. The capital program also included numerous well workovers, reactivations, ›ipeline projects, facility modifications and general maintenance which at the end of the drilling season d increased the Company's net production to approximately 600 boe/d. This level of activity is ›ical of a winter program and results in a capital commitment to Delphi of approximately $5.0 million ınually. Although Fontas is not considered a "growth" property, the consistency and predictability of e development program coupled with the high operating netbacks associated with a company owned ility, make this a very desirable property from a cash flow perspective. Fontas is currently producing oximately 370 boe/d net to Delphi.

g the year, the majority working interest partner and operator of the property sold its working interest l and gas royalty trust. For the winter of 2006/2007, the new operator has significantly scaled back ital program to focus on remedial well work and maintenance projects, taking the time to further the property and develop a go forward plan. Due to the high cost of services for building winter roads and transporting and establishing field camp facilities, the operator is considering a more capital program every other year to improve the economics of the capital program.

lberta

ntral Alberta assets produced approximately 500 boe/d net to Delphi in 2006, consisting of 80 ent medium and heavy oil and 20 percent natural gas. The Company has an average working interest percent in the producing properties and an undeveloped land position of approximately 5,700 net On these lands the Company has identified numerous infill and step-out drilling locations primarily on four properties: Horseshoe, Hayter, Thompson Lake and Sounding Lake.

During 2006, the Company incurred capital expenditures of approximately $1.4 million performing well reactivations and facility optimizations. While it is difficult to generate production growth with such a modest level of capital expenditures, the Company has been able to minimize production declines. In 2007, the Company will be pursuing multiple infill and step-out drilling opportunities and continued well reactivation work due to the lower capital costs and improved overall economics associated with the strength in crude pricing. The assets are currently producing approximately 400 boe/d net to Delphi.

20% increase in prove
plus probable reserve

exploration

Delphi's exploration team has continued its efforts to define future growth opportunities for the Company. The Company focuses its efforts on those areas and plays where it has existing in-house expertise. Emphasis is placed on multizone sweet gas targets with substantial future development upside. The Company makes use of its industry relationships to capture opportunities on both new and existing acreage.

Tower Creek, Alberta

At Tower Creek, operations to equip and tie-in the Company's exploration discovery are proceeding on schedule and are anticipated to be completed in the second quarter of 2007. As previously announced, Delphi and its working interest partners have signed an agreement with a midstream company that will construct an 18 kilometre, 8-inch diameter, high-pressure, sour gas pipeline to tie-in the well to the Kaybob South # 3 gas plant for processing, where significant excess capacity is available. Initial gross raw gas production rates are estimated to be between 20 and 25 mmcf/d (500 to 600 boe/d net to Delphi).

The second exploration test is scheduled to start drilling after spring break-up. This seismically defined deep exploration test is targeting high pressure sweet gas from the highly fractured Wabamun formation. Wabamun analogs in the area have commenced production at gross raw rates of up to 30 mmcf/d of sweet gas. Delphi will pay 23.9 percent of the costs of the well to earn a 20.8 percent working interest in the wellbore and surrounding acreage.

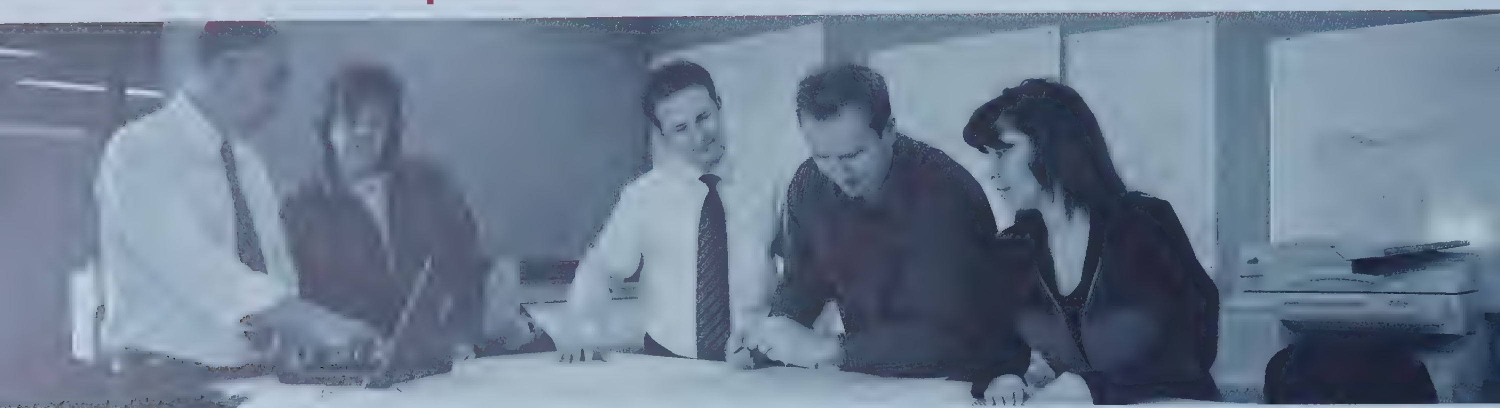
Brazeau, Alberta

At Brazeau, the Company intends to drill a twin well to an earlier discovery targeting several sandstone reservoirs within the Belly River Formation. Analogue production on offsetting lands ranges from 100 to 500 boe/d per well. Delphi has a 27 percent working interest in 2,560 acres where up to 8 development wells could be drilled upon success.

Cutbank, British Columbia

At Cutbank, the Company is currently in discussions with senior oil and gas producers regarding potential joint operations to develop existing acreage in this area. Delphi has a 50 percent working interest in a previously drilled exploration well which has successfully tested natural gas from two Cretaceous zones at rates in excess of 1,000 mcf/d. Several step-out locations to this discovery have been identified as part of a development program which would incorporate the tie-in of the existing discovery well.

14\ operational statistics



reserves

In a report dated February 28, 2007, GLJ Petroleum Consultants Ltd. ("GLJ"), the Company's independent petroleum engineering firm, evaluated the crude oil, natural gas and natural gas liquids reserves of the Company as at December 31, 2006 and prepared a reserves report in accordance with National Instrument 51-101 "standards of Disclosure for Oil and Gas Activities". GLJ based its evaluation on land data, well and geological information, reservoir studies, estimates of on-stream dates, contract information, operating cost lata, capital budgets and future operating plans provided by the Company and information obtained from public records and GLJ's nternal non-confidential files and commodity price forecast. The Audit and Reserves Committee, with the mandate of reviewing the dependent engineering report, recommended the acceptance of the GLJ reserve estimates and it has been approved by the Board Directors for the purposes of the annual report.

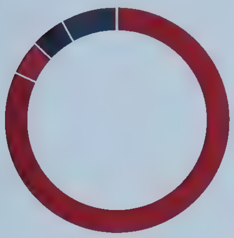
reserves reconciliation

econciliation of the Company's proved, probable and proved plus probable reserves for December 31, 2006 is as follows:

nciliation of Company Gross Reserves [1]

	Crude oil and NGL (mbbls)			Natural gas (mmcf)			Mboe (6:1)		
	Proved	Probable	Total	Proved	Probable	Total	Proved	Probable	Total
mber 31, 2005	1,977	934	2,911	50,660	18,421	69,081	10,420	4,004	14,424
ries and extensions	539	392	931	25,959	12,949	38,908	4,865	2,550	7,415
cal revisions	(426)	253	(173)	(5,478)	(3,104)	(8,582)	(1,338)	(265)	(1,603)
tions	(117)	(84)	(201)	(3,661)	(1,745)	(5,406)	(728)	(374)	(1,102)
	2	–	2	457	41	498	79	7	86
	1,975	1,495	3,470	67,937	26,562	94,499	13,298	5,922	19,220
iction	(345)	–	(345)	(9,383)	–	(9,383)	(1,909)	–	(1,909)
)ecember 31, 2006	1,630	1,495	3,125	58,554	26,562	85,116	11,389	5,922	17,311

Gross reserves represent the Company's interest before deducting royalties and include any royalty interest of the Company.



summary of reserves

The following table outlines the oil and natural gas liquids and natural gas reserves of the Company by product type on a Company interest (before royalties) basis. Proved reserves increased nine percent as compared to 2005 and proved plus probable reserves increased by 20 percent. Proved plus probable natural gas reserves increased 23 percent compared to the previous year.

Company Gross Reserves [1]	*2006*	*2005*	*% Change*
Proved producing oil & NGLs (mbbls)	*1,294*	*1,516*	*(15)*
Proved producing natural gas (mmcf)	*39,401*	*41,446*	*(5)*
Total proved producing (mboe)	*7,861*	*8,424*	*(7)*
Proved oil & NGLs (mbbls)	*1,630*	*1,977*	*(18)*
Proved natural gas (mmcf)	*58,554*	*50,660*	*16*
Total proved (mboe)	*11,389*	*10,420*	*9*
Probable oil & NGLs (mbbls)	*1,495*	*934*	*60*
Probable natural gas (mmcf)	*26,562*	*18,421*	*44*
Total probable (mboe)	*5,922*	*4,004*	*48*
Proved plus probable oil & NGLs (mbbls)	*3,125*	*2,911*	*7*
Proved plus probable natural gas (mmcf)	*85,116*	*69,081*	*23*
Total proved plus probable (mboe)	*17,311*	*14,424*	*20*

[1] Gross reserves represent the Company's interest before deducting royalties and include any royalty interest of the Company.

escalated pricing assumptions

The following table sets forth GLJ's escalated commodity price, currency exchange rate and inflation rate forecasts used in the preparation of the reserve estimates of the Company.

Pricing Assumptions	*West Texas Intermediate (US$/bbl)*	*Edmonton Light (CDN$/bbl)*	*AECO Spot (CDN$/mmbtu)*	*Exchange Rate (US$/CDN$)*	*Inflation (%)*
2007	62.00	70.25	7.20	0.87	2.0
2008	60.00	68.00	7.45	0.87	2.0
2009	58.00	65.75	7.75	0.87	2.0
2010	57.00	64.50	7.80	0.87	2.0
2011	57.00	64.50	7.85	0.87	2.0
2012	57.50	65.00	8.15	0.87	2.0
2013	58.50	66.25	8.30	0.87	2.0
2014	59.75	67.75	8.50	0.87	2.0
2015	61.00	69.00	8.70	0.87	2.0
2016	62.25	70.50	8.90	0.87	2.0
2017	63.50	71.75	9.10	0.87	2.0
Thereafter [1]					

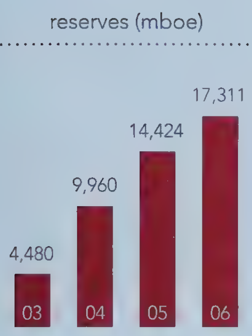
[1] Percentage change of 2% represents the change in future prices each year after 2017 to the end of the reserve life.

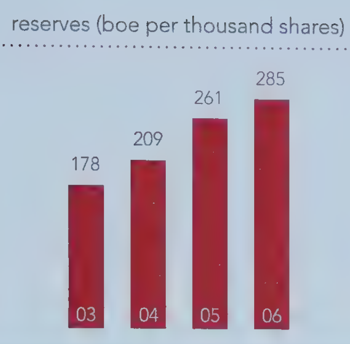
net present value of reserves – escalated pricing [1]

The net present values of future net revenue of the Company's reserves at various discount rates on a before income tax basis are outlined below.

(CDN$ thousands)	*Undiscounted*	*Discounted at 8%*	*Discounted as 10%*
Proved			
Developed producing	216,254	156,888	147,199
Developed non-producing	63,895	41,157	37,717
Undeveloped	30,577	11,478	9,263
Total proved	310,726	209,523	194,179
Probable	162,714	77,420	67,109
Total proved plus probable	473,440	286,943	261,288

[1] As required by NI 51-101, undiscounted well abandonment costs of $5.6 million, eight percent discounted of $3.0 million and 10 percent discounted of $2.7 million for total proved and $7.3 million, $3.4 million and $2.9 million respectively, for total proved plus probable reserves are included in the net present value determination.





finding and development costs

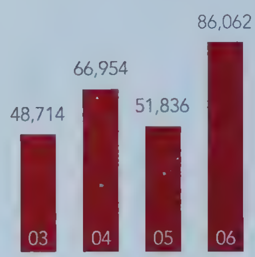
The Company has presented its finding and development costs in accordance with NI 51-101. The Company has also calculated finding and development costs including acquisitions and dispositions. Finding and development costs in 2006 were negatively affected by the significant capital program directed towards Bigfoot in North East British Columbia whereby Delphi incurred 90 percent of the capital costs ($91.4 million) to earn a 50 percent working interest in the property. The incremental costs in excess of the 50 percent earned interest on the drilling expenditures were approximately $20.7 million or $4.17/boe on a proved plus probable basis.

	2006	*2005*	*Average 2004-2006*
Capital invested (CDN$ thousands)			
Land and seismic	13,648	345	15,443
Drilling and completion	86,473	37,187	144,562
Other	1,906	1,364	5,363
Facilities	62,137	22,299	93,307
	164,164	61,195	258,675
Change in future development costs			
Proved reserves	12,085	1,910	18,432
	176,249	63,105	277,107
Probable reserves	11,147	(1,248)	21,685
Total on-stream costs	187,396	61,857	298,792
Acquisitions	1,188	51,273	104,852
Dispositions	(34,918)	(5,862)	(40,780)
Total capital invested	153,666	107,268	362,864
Reserve discoveries, extensions and revisions			
Proved (mboe)	3,527	2,979	7,315
Proved plus probable reserves (mboe)	5,812	3,214	10,021
Reserve net additions [1]			
Proved (mboe)	2,878	5,200	12,267
Proved plus probable reserves (mboe)	4,796	6,005	16,905
Finding and development costs ($/boe) [2]			
On-stream costs excluding future development costs			
Proved	46.54	20.54	35.36
Proved plus probable reserves	28.25	19.04	25.81
On-stream costs including future development costs			
Proved	49.97	21.18	37.88
Proved plus probable reserves	32.24	19.25	29.82
Total capital invested			
Proved	53.39	20.87	29.58
Proved plus probable reserves	32.04	17.86	21.46

(1) Includes discoveries, extensions, revisions, acquisitions and dispositions.

(2) The aggregate of the exploration and development costs incurred in the most recent financial year, included in capital invested, and the change in estimated future development costs, generally will not reflect total finding and development costs related to reserve additions for that year.

undeveloped land (acres)



reserve life index

The reserve life index of Delphi has been calculated by using average 2006 production of 5,228 boe/d. The reserve life index is greater than nine years on a proved plus probable basis.

	Crude oil and NGL (mbbls)			*Natural gas (mmcf)*			*Mboe (6:1)*		
	Proved	*Probable*	*Total*	*Proved*	*Probable*	*Total*	*Proved*	*Probable*	*Total*
Reserves – December 31, 2006	1,630	1,495	3,125	58,554	26,562	85,116	11,389	5,922	17,311
Production	345		345	9,383		9,383	1,909		1,909
Reserves life index (years)	4.7		9.1	6.2		9.1	6.0		9.1

reserves per outstanding common share

The proved plus probable reserves per 1,000 common shares of the Company was 285 compared to 261 in the previous year, an increase of nine percent.

	2006	*2005*	*% Change*
Proved and probable reserves (mboe)	17,311	14,424	20
Proved and probable boe reserves per 1,000 outstanding common shares	285	261	9

acreage summary

The Company's total and undeveloped landholdings by geographic focus area as at December 31, 2006 are outlined below.

	Total		*Undeveloped*		*Fair Market*
and CDN$ thousands)	*Gross*	*Net*	*Gross*	*Net*	*Value* [1]
North West Alberta	221,560	53,548	121,440	22,457	7,081
North East British Columbia	251,140	87,950	145,141	57,932	10,536
East Central Alberta	27,403	20,106	8,000	5,673	1,059
otal	500,103	161,604	274,581	86,062	18,676

Undeveloped land value of $18.7 million at December 31, 2006 for undeveloped land based on Seaton-Jordan & Associates Ltd. land valuation report.

recycle ratio

The recycle ratio is a measure of the effectiveness of the Company's re-investment program. The recycle ratio is a key indicator in the oil and gas industry of efficiency and profitability and is calculated by dividing the finding and development costs for total capital invested into the Company's operating netback.

For the years ended December 31 ($/boe)	*2006*	*2005*
Operating netback	*30.49*	*30.24*
Proved plus probable reserves F&D costs	*32.04*	*17.86*
Proved plus probable recycle ratio	*0.95*	*1.69*

net asset value

The net asset values of the Company for December 31, 2006 at a discount rate of eight and 10 percent before taxes are summarized below.

(CDN$ thousands)	*8%*	*10%*
Estimated net future revenues of proved plus probable reserves discounted	*286,943*	*261,288*
Undeveloped land and seismic [(1)]	*22,000*	*22,000*
Mark-to-market value of hedging contracts	*9,275*	*9,275*
In-the-money option proceeds [(2)]	*1,397*	*1,397*
Total asset value	*319,615*	*293,960*
Bank debt plus working capital deficiency	*(118,178)*	*(118,178)*
Net asset value	*201,437*	*175,782*
Common shares outstanding and in-the-money options	*61,727,191*	*61,727,191*
Net asset value per share	*3.26*	*2.85*

(1) Undeveloped land and seismic includes value of $18.7 million at December 31, 2006 for undeveloped land based on Seaton-Jordan & Associates Ltd. land valuation report.

(2) In-the-money option proceeds are based on the closing December 31, 2006 share price of $2.48.

(3) The Company estimates it has approximately $209 million of tax deductions available to offset future taxable income.

20\ management's discussion & analysis

(all tabular amounts are expressed in thousands of CDN dollars, except per unit amounts)

The following discussion and analysis has been prepared by management and reviewed and approved by the Board of Directors of Delphi Energy Corp ("Delphi" or "the Company"). The discussion and analysis is a review of the financial results of the Company based upon accounting principles generally accepted in Canada. Its focus is primarily a comparison of the financial performance for the three and 12 months ended December 31, 2006 and 2005 and should be read in conjunction with the audited financial statements and accompanying notes for the year ended December 31, 2006. The discussion and analysis has been prepared as of March 6, 2007.

Basis of Presentation

For the purpose of reporting production information, reserves and calculating unit prices and costs, natural gas volumes have been converted to a barrel of oil equivalent (boe) using six thousand cubic feet equal to one barrel. A boe conversion ratio of 6:1 is based upon an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. This conversion conforms with the Canadian Securities Administrators' National Instrument 51-101 when boes are disclosed. Boes may be misleading, particularly if used in isolation.

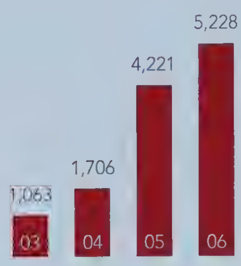
Non GAAP Measures

The MD&A contains the terms "funds from operations", "funds from operations per share" and "netbacks" which are not recognized measures under Canadian generally accepted accounting principles. The Company uses these measures to help evaluate its performance. Management considers netbacks an important measure as it demonstrates its profitability relative to current commodity prices. Management uses funds from operations to analyze performance and considers it a key measure as it demonstrates the Company's ability to generate the cash necessary to fund future capital investments and to repay debt. Funds from operations has been defined by the Company as net earnings plus the addback of non-cash items (depletion, depreciation and accretion, stock-based compensation, future income taxes and unrealized (gain)/loss on risk management activities) and excludes the change in non-cash working capital related to operating activities and expenditures on asset retirement obligations and reclamation. The Company also presents funds from operations per share whereby amounts per share are calculated using weighted average shares outstanding consistent with the calculation of earnings per share. Delphi's determination of funds from operations may not be comparable to that reported by other companies nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP.

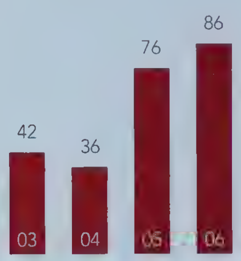
Forward-Looking Statements

Certain information regarding Delphi Energy Corp. set forth in this document, including management's assessment of the Company's future plans and operations, contains forward-looking statements that involve substantial known and unknown risks and uncertainties. These forward-looking statements are subject to numerous risks and uncertainties, certain of which are beyond the Company's control, including the effects of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other oil and gas companies, the lack of availability of qualified personnel or management, stock market volatility and ability to access sufficient capital from both internal and external sources. The Company's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements, and accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur.

production (boe/d)



production (boe/d per million shares)



production

		Three Months Ended December 31			Twelve Months Ended December 31	
	2006	2005	% Change	2006	2005	% Change
Natural gas (mcf/d)	24,919	22,909	9	25,706	19,848	30
Crude oil (bbl/d)	388	573	(32)	476	614	(22)
Natural gas liquids (bbl/d)	441	455	(3)	468	299	57
Total (boe/d)	4,982	4,846	3	5,228	4,221	24

Production for the 12 months ended December 31, 2006 averaged 5,228 boe/d representing an increase of 24 percent over the comparative period primarily due to successful drilling programs at Bigstone, Alberta ("Bigstone") and in the Bigfoot area of North East British Columbia ("Bigfoot"). Although Delphi was successful with the drill bit in 2006, production was less than anticipated due to higher than expected declines on wells drilled in Bigstone at the end of 2005, minimal capital directed towards drilling activities in the second half of 2006, numerous facility interruptions throughout the year and processing constraints at certain properties. The Company's production portfolio for the year was weighted 82 percent to natural gas, nine percent to crude oil and nine percent to natural gas liquids. Production for the three months ended December 31, 2006 ("the Quarter") decreased two percent from the third quarter of 2006 due to natural declines and the sale of approximately 250 boe/d at the end of November 2006. The Company [illegible] there are approximately 900 boe/d behind pipe awaiting tie-in which is expected to occur in the first and second quarters [illegible] 2007 with the majority of behind pipe volumes being related to the Company's exploration discovery at Tower Creek. Delphi is [illegible]ecting production for 2007 to average 5,200 to 5,400 boe/d with an exit rate of approximately 5,700 boe/d.

[illegible]ude oil production was 32 percent and 22 percent lower as compared to the comparative periods in 2005 due to the sale of [illegible]roximately 50 boe/d, natural declines and minimal capital investment towards adding new production.

[illegible]s liquids (NGL) production, primarily condensate, has increased significantly as a result of the high yield of liquids associated [illegible] creased natural gas production at Bigstone.

[illegible]lity prices and risk management

[illegible]rk Prices

		Three Months Ended December 31			Twelve Months Ended December 31	
	2006	2005	% Change	2006	2005	% Change
[illegible]						
[illegible]((US $/mmbtu)	6.65	12.36	(46)	6.75	8.89	(24)
[illegible]O (CDN $/mcf)	6.90	11.61	(41)	6.55	8.81	(26)
[illegible]						
West Texas Intermediate (US $/bbl)	59.95	60.05	–	66.00	56.70	16
Edmonton Light (CDN $/bbl)	65.45	72.11	(9)	72.90	69.82	4
[illegible] exchange rate						
Canadian to US dollar	1.14	1.17	(3)	1.13	1.21	(7)
US to Canadian dollar	0.88	0.85	3	0.88	0.83	6

Natural Gas

United States natural gas prices are commonly referenced to the New York Mercantile Exchange Henry Hub in Louisiana ("NYMEX") while Canadian natural gas prices are typically referenced to the AECO Hub in Alberta. Natural gas prices are influenced more by North American supply and demand than global fundamentals. In 2006, it was a challenging year for natural gas prices as a warm winter early in the year followed by a relatively cool summer failed to eradicate the record amount of natural gas inventory in storage resulting in a sharp decrease in the price of natural gas. During the year, the AECO average daily spot price ranged from a high of $8.60 per thousand cubic feet to a low of $4.69 per thousand cubic feet. Delphi expects prices to remain volatile throughout 2007 and as such, has extended its price protection strategy to protect the Company's capital program and its balance sheet. Currently, Delphi has hedged approximately 55 percent of its before-royalty gas production at an average AECO floor price of $8.96 per thousand cubic feet from January 1, 2007 to March 31, 2008. Delphi believes the long term supply and demand fundamentals for natural gas will support stronger, less volatile prices in the future.

Crude Oil

West Texas Intermediate at Cushing, Oklahoma ("WTI") is the benchmark reference for North American crude oil prices. Canadian crude oil prices are based upon postings, primarily at Edmonton, Alberta, and represent the WTI price adjusted for quality and transportation differentials as well as the US/CDN dollar exchange rate. In contrast to natural gas prices, 2006 was an excellent year for crude oil prices which continued to show sustained strength due to several major production disruptions, geopolitical unrest in major oil producing countries in the Middle East and Africa and strong global demand.

The prices received for crude oil are related to the price of crude oil in world markets. Prices for heavy oil and other lesser quality crudes trade at a discount or differential to light crude oil due to the additional costs in the refining process. The differential narrowed in 2006 averaging $21.70 per barrel compared to $24.17 per barrel in 2005. The narrowing of the differential was the primary driver of a 14 percent increase in Bow River crude prices, a benchmark for medium grade oil prices.

Risk Management Activities

Delphi enters into both financial and physical commodity contracts as part of its risk management program to manage commodity price fluctuations designed to ensure sufficient cash is generated to fund its capital program particularly when commodity prices are extremely volatile.

The Company has chosen to mark-to-market its financial commodity contracts and record any unrealized gain or loss. The estimated fair value of unrealized derivative instruments is reported on the balance sheet with any change in the unrealized positions booked to earnings. The Company recognized an unrealized non-cash gain on risk management activities for the year ended December 31, 2006 of $1.0 million related to financial commodity contracts. During the year ended December 31, 2006, Delphi recorded a realized loss on financial commodity contracts of $0.2 million. The estimated fair value of Delphi's physical and financial contracts at December 31, 2006 was approximately $8.9 and $0.3 million respectively. The fair values of these contracts are based on an approximation of the amounts that would have been paid to or received from counterparties to settle the contracts outstanding at the end of the period with reference to forward prices and market values provided by independent sources. Due to the inherent volatility in commodity prices, actual amounts realized may differ from these estimates.

The Company has fixed the price applicable to future production through the following contracts:

Time Period	Commodity	Type of Contract	Quantity Contracted	Canadian Price (CDN$/unit)
November 2006 – March 2007	Natural Gas	Physical	2,000 GJ/d	$10.00 fixed
November 2006 – March 2007	Natural Gas	Physical	4,000 GJ/d	$9.50 floor/$10.65 ceiling
November 2006 – March 2007	Natural Gas	Physical	2,000 GJ/d	$9.50 floor/$11.35 ceiling
November 2006 – March 2007	Natural Gas	Physical	4,000 GJ/d	$8.75 floor/$10.00 ceiling
November 2006 – March 2007	Natural Gas	Physical	2,000 mmbtu/d	$11.05 floor/$12.92 ceiling
January 2007 – March 2007	Natural Gas	Financial	2,000 GJ/d	$6.50 floor/$10.45 ceiling
April 2007 – October 2007	Natural Gas	Physical	3,000 GJ/d	$8.75 floor/$9.55 ceiling
pril 2007 – October 2007	Natural Gas	Physical	4,000 GJ/d	$8.00 floor/$8.92 ceiling
ril 2007 – October 2007	Natural Gas	Physical	2,000 mmbtu/d	$8.94 fixed
pril 2007 – October 2007	Natural Gas	Physical	2,000 GJ/d	$6.50 floor/$8.15 ceiling
ril 2007 – October 2007	Natural Gas	Financial	2,000 GJ/d	$6.50 floor/$9.00 ceiling
vember 2007 – December 2007	Natural Gas	Financial	2,000 GJ/d	$6.50 floor/$10.45 ceiling
ember 2007 – March 2008	Natural Gas	Physical	3,000 GJ/d	$9.00 floor/$9.98 ceiling
ember 2007 – March 2008	Natural Gas	Physical	2,000 mmbtu/d	$11.07 fixed
ember 2007 – March 2008	Natural Gas	Physical	2,000 GJ/d	$7.75 floor/$9.03 ceiling
ember 2007 – March 2008 (1)	Natural Gas	Physical	2,000 GJ/d	$8.00 floor/$10.02 ceiling
pril 2008 – October 2008	Natural Gas	Physical	4,000 GJ/d	$7.21 fixed

red into subsequent to year-end.

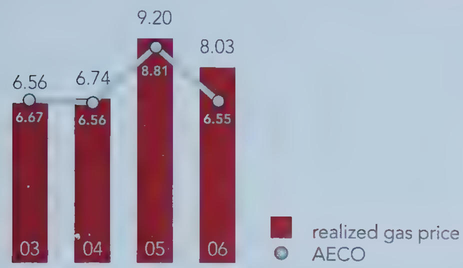
tract prices on physical contracts are recognized in earnings in the same period as the production revenue.

ized sales prices

	Three Months Ended December 31			Twelve Months Ended December 31		
	2006	2005	% Change	2006	2005	% Change
ral gas ($/mcf)	8.41	12.17	(31)	8.05	9.37	(14)
loss) on financial contracts ($/mcf)	–	(0.48)	100	(0.02)	(0.17)	(88)
ed gas price ($/mcf)	8.41	11.69	(28)	8.03	9.20	(13)
e oil ($/bbl)	47.09	43.49	8	53.19	45.48	17
financial contracts ($/bbl)	–	(7.85)	100	–	(7.10)	100
Realized oil price ($/bbl)	47.09	35.64	32	53.19	38.38	39
Natural gas liquids ($/bbl)	48.55	58.35	(17)	56.25	51.82	9
sales price ($/boe)	50.02	64.94	(23)	49.36	52.48	(6)

The decrease in the average natural gas price received by Delphi during the three and 12 months ended December 31, 2006, is consistent with the significant decrease in the AECO spot price. The Company continues to receive higher than the AECO spot price on natural gas sales due to the high heating content of natural gas production and the sale of approximately 19 percent of the Company's

natural gas prices ($/mcf)



production being priced at Chicago from sales on the Alliance Pipeline for the three and 12 months ended December 31, 2006. During the three and 12 months ended December 31, 2006, Delphi benefited from its risk management program in which the Company fixed the price on a portion of its natural gas production at amounts significantly higher than the AECO spot price. The risk management program increased the average natural gas price received during the Quarter by approximately $1.30 per mcf and $1.12 per mcf for the year. The increase in the average oil price received by Delphi during the 12 months ended December 31, 2006, is consistent with the upward trend of the benchmark WTI and the narrowing of the quality differential, offset by the strengthening of the Canadian dollar. Delphi's oil production is predominantly a medium grade oil therefore the Company's average price fluctuates with the quality differential. During the Quarter, Delphi's realized oil price increased due to higher production from Delphi's light oil discovery at Bigstone. Realized natural gas liquids prices have increased due to the increase in the price received for condensate, the primary component of the Company's natural gas liquids production.

revenue

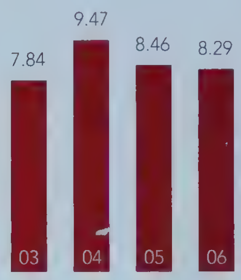
	Three Months Ended December 31			Twelve Months Ended December 31		
	2006	*2005*	*% Change*	*2006*	*2005*	*% Change*
Natural gas	***19,277***	*25,652*	*(25)*	***75,523***	*67,898*	*11*
Crude oil	***1,681***	*2,293*	*(27)*	***9,242***	*10,209*	*(9)*
Natural gas liquids	***1,970***	*2,447*	*(20)*	***9,609***	*5,657*	*70*
Realized loss on financial contracts	–	*(1,431)*	*(100)*	***(185)***	*(2,884)*	*(94)*
Total	***22,928***	*28,961*	*(21)*	***94,189***	*80,880*	*16*

The increase in revenue for the 12 months ended December 31, 2006, over the comparative period is attributable to increased production volumes offset by a decrease in the realized price received due to lower natural gas prices. Revenue for the 12 months ended December 31, 2006 increased 16 percent over the comparative period due to a 24 percent increase in production volumes offset by a six percent decrease in the realized price received. Revenue during the Quarter decreased 21 percent over the comparative period due to a 23 percent decrease in the average price received offset by a three percent increase in production volumes.

royalties

	Three Months Ended December 31			Twelve Months Ended December 31		
	2006	*2005*	*% Change*	*2006*	*2005*	*% Change*
Crown	***3,909***	*6,929*	*(44)*	***16,915***	*17,314*	*(2)*
Freehold and gross overriding	***203***	*247*	*(18)*	***908***	*1,131*	*(20)*
Total	***4,112***	*7,176*	*(43)*	***17,823***	*18,445*	*(3)*
Royalty credits	***(1,302)***	*(630)*	*107*	***(4,092)***	*(2,110)*	*94*
Net	***2,810***	*6,546*	*(57)*	***13,731***	*16,335*	*(16)*
Per boe	***6.13***	*14.68*	*(58)*	***7.20***	*10.60*	*(32)*
Percent of total revenue	***12.3***	*22.6*		***14.6***	*20.2*	

operating costs ($/boe)



The Company pays royalties to provincial governments ("Crown"), freeholders, which can be individuals or companies, and other oil and gas operators, who own surface or mineral rights. Crown royalty rates are calculated on a sliding scale based on commodity prices and individual well production rates. Royalty rates can change due to price fluctuations or changes in production volumes on a well by well basis subject to a minimum and maximum rate restriction ascribed by the Crown. During the three and 12 months ended December 31, 2006, royalties as a percentage of revenue decreased to 12.3 percent and 14.6 percent due to Delphi realizing approximately $3.5 million and $10.5 million in hedging gains, included in revenue, but on which royalties are not paid. In Alberta, Delphi pays royalties based on the provincial reference price not the prices received resulting in Delphi not paying royalties on the incremental $3.5 million and $10.5 million in hedging gains. Delphi is expecting royalties as a percentage of revenue before hedging to be between 17 – 20 percent in 2007.

Royalty credits for the three and 12 month period ended December 31, 2006 are higher than the comparative periods due to capital being spent on natural gas infrastructure which has resulted in an increase in the Gas Cost Allowance ("GCA") credit. The GCA is a deduction from Alberta Crown royalties to compensate the Company for the cost of gathering, processing and compression facilities to process the Crown royalty portion of production. The Company receives the Alberta Royalty Tax Credit ("ARTC"), a tax rebate from the Alberta government for eligible Crown royalties paid in the year subject to a maximum of $0.5 million in 2006. The Alberta government recently announced that the ARTC tax rebate program will be cancelled and as such, Delphi will not receive the rebate in 2007 and forward.

operating expenses

	Three Months Ended December 31			*Twelve Months Ended December 31*		
	2006	*2005*	*% Change*	*2006*	*2005*	*% Change*
Total	*3,859*	*3,523*	*10*	*15,826*	*13,041*	*21*
Per boe	*8.42*	*7.90*	*7*	*8.29*	*8.46*	*(2)*

Operating expenses on a per boe basis for the 12 months ended December 31, 2006, decreased two percent over the comparative period despite an environment which faced strong inflationary pressures. Despite the decrease in natural gas prices in 2006, the industry still experienced increased costs for services, supplies, materials, electricity and labour. Operating costs during the Quarter decreased four percent from the third quarter of 2006 and increased seven percent over the comparative period in 2005.

transportation expenses

	Three Months Ended December 31			*Twelve Months Ended December 31*		
	2006	*2005*	*% Change*	*2006*	*2005*	*% Change*
Total	*1,627*	*1,418*	*15*	*6,455*	*4,893*	*32*
Per boe	*3.55*	*3.18*	*12*	*3.38*	*3.18*	*6*

In British Columbia, infrastructure is owned by Duke Energy that enables natural gas producers to avoid facility construction in exchange for regulated gathering, processing and transmission fees. This all-in charge is included in transportation expenses.

On a per boe basis, transportation costs for the three and 12 months ended December 31, 2006 increased over the comparative periods due to production from the Bigfoot area being brought on-stream in the second quarter of 2006. For the three and 12 months ended December 31, 2006, approximately 25 – 30 percent of the Company's natural gas production from the Bigstone area was shipped on the Alliance Pipeline and sold in Chicago. The costs of transmission from the field to Chicago are included in transportation expenses. The volumes shipped on the Alliance Pipeline have higher than the corporate average transportation costs; however, these costs are partially offset by the higher price received at Chicago.

general and administrative

	Three Months Ended December 31			Twelve Months Ended December 31		
	2006	2005	% Change	**2006**	2005	% Change
General and administrative costs	**1,339**	1,252	7	**5,498**	4,666	18
Overhead recoveries	**(137)**	(434)	(68)	**(1,081)**	(869)	24
Salary allocations	**(413)**	(395)	5	**(2,045)**	(1,306)	57
Net	**789**	423	87	**2,372**	2,491	(5)
Per boe	**1.72**	0.95	81	**1.24**	1.62	(23)

On a per boe basis, general and administrative ("G&A") costs for the 12 months ended December 31, 2006 decreased 23 percent from the comparative period in 2005. The decrease in G&A is due to an increase in production with minimal amount of increased personnel costs. During the Quarter, G&A per boe increased 60 percent from the third quarter of 2006 due to decreased overhead recoveries as capital spending was limited during the Quarter, lower production volumes and overall higher corporate costs, primarily office rent. On a gross basis, G&A for the three and 12 months ended December 31, 2006 has increased seven and 18 percent respectively, commensurate with increased staffing and activity levels. As a result of unprecedented levels of activity for Delphi and for the industry as a whole, the costs associated with hiring, compensating, and retaining employees and consultants have risen.

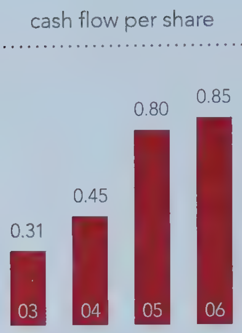
For the three and 12 months ended December 31, 2006, salary allocations have increased by five percent and 57 percent due to increased technical staff efforts toward the Company's exploration and development program. Overhead recoveries have increased over the prior year due to higher capital spending.

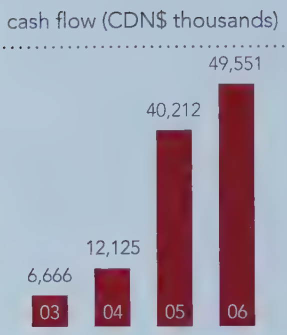
stock-based compensation

	Three Months Ended December 31			Twelve Months Ended December 31		
	2006	2005	% Change	**2006**	2005	% Change
Total	**317**	382	(17)	**2,491**	1,631	53
Per boe	**0.69**	0.86	(20)	**1.31**	1.06	24

Stock-based compensation expense is the amortization over the vesting period of the fair value of stock options granted to employees, directors and key consultants of the Company. The fair value of all options granted is estimated at the date of grant using the Black-Scholes option pricing model. The non-cash compensation expense for the 12 months ended December 31, 2006, increased 53 percent due to options being granted to staff to facilitate the growth of the Company and to retain current staff in today's

competitive environment. Delphi believes providing an employee with stock options is an effective way to align the employees' goals with the shareholders and retain key employees. Pursuant to Delphi's option plan, one-third of the options granted vest immediately resulting in higher initial compensation expense. During the three and 12 months ended December 31, 2006, Delphi capitalized \$0.3 and \$0.9 million of stock-based compensation associated with exploration and development activities.





interest

	Three Months Ended December 31			*Twelve Months Ended December 31*		
	2006	*2005*	*% Change*	*2006*	*2005*	*% Change*
Total	***2,026***	*883*	*129*	***6,254***	*3,658*	*71*
Per boe	***4.42***	*1.98*	*123*	***3.28***	*2.37*	*38*

Interest expense on a per boe basis increased 123 percent and 38 percent over the comparable periods due to higher bank debt from increased capital spending and higher average interest rates. Interest expense on a gross and per boe basis increased from the third quarter due to higher debt balances and interest rates along with lower production volumes.

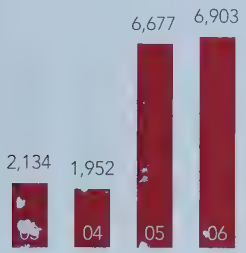
depletion, depreciation and accretion

	Three Months Ended December 31			*Twelve Months Ended December 31*		
	2006	*2005*	*% Change*	*2006*	*2005*	*% Change*
Depletion and depreciation	***11,090***	*8,329*	*33*	***39,727***	*26,568*	*50*
retion expense	***173***	*166*	*4*	***637***	*526*	*21*
	11,263	*8,495*	*33*	***40,364***	*27,094*	*49*
boe	***24.58***	*19.05*	*29*	***21.15***	*17.59*	*20*

epletion, depreciation, and accretion per boe increased 29 percent and 20 percent, respectively, for the three and 12 months ended cember 31, 2006. This increase is attributable to higher cost proved reserve additions through drilling and acquisitions, which is a nd throughout the industry. Throughout 2006, Delphi invested a significant amount of capital towards field infrastructure, allocated depletable costs on a reasonable basis, which does not immediately increase proved reserves but is critical to current operations future development plans. The higher depletion and depreciation is indicative of the reality that the Western Canada Sedimentary is one of the most expensive basins in the world to add proved reserves. The increase in total depletion and depreciation versus the comparative periods is a result of increased production levels and a higher per boe rate.

ccretion expense of asset retirement obligations relates to the passing of time until the Company estimates it will retire its assets and store the asset locations to a condition which meets or exceeds environmental standards. Due to the long-term nature of certain sets of the Company, this accretion expense is estimated to extend over a term of three to 20 years. The Company uses a credit justed risk-free rate of eight percent for the purpose of calculating the fair value of its asset retirement obligations and hence the ccretion expense. The accretion expense for the three and 12 months ended December 31, 2006 increased four and 21 percent over e comparative periods. The increase is due to an extensive drilling program in 2006.

net earnings (CDN$ thousands)



taxes

	Three Months Ended December 31			Twelve Months Ended December 31		
	2006	2005	% Change	**2006**	2005	% Change
Capital	**–**	49	(100)	**–**	250	(100)
Future (recovery)	**295**	3,464	(91)	**786**	4,165	(81)
Total	**295**	3,513	(92)	**786**	4,415	(82)

The provision for future income taxes for the three and 12 months ended December 31, 2006 were $0.3 million and $0.8 million resulting in an effective tax rate of 50 and 10 percent. The 12 months ended December 31, 2006 includes a recovery of $3.0 million relating to a reduction in future federal and provincial income tax rates enacted during the second quarter. The Company did not record any capital taxes in 2006 as capital taxes were eliminated effective January 1, 2006 pursuant to the federal government budget of May 2, 2006. Delphi does not anticipate it will be cash taxable until 2008 or later based on current commodity prices.

funds from operations

	Three Months Ended December 31			Twelve Months Ended December 31		
	2006	2005	% Change	**2006**	2005	% Change
Net earnings	**290**	6,425	(95)	**6,903**	6,677	3
Non-cash items						
Depletion, depreciation and accretion	**11,263**	8,495	33	**40,364**	27,094	49
Unrealized loss/(gain) on risk management activities	**(348)**	(2,648)	(87)	**(993)**	645	(254)
Stock-based compensation expense	**317**	382	(17)	**2,491**	1,631	53
Future income taxes	**295**	3,464	(91)	**786**	4,165	(81)
Funds from operations	**11,817**	16,118	(27)	**49,551**	40,212	23

For the three and 12 months ended December 31, 2006 funds from operations were $11.8 million ($0.19 per basic share) and $49.6 million ($0.85 per basic share) compared to $16.1 million (2005 - $0.31 per basic share) and $40.2 million (2005 - $0.80 per basic share).

net earnings

For the three and 12 months ended December 31, 2006, Delphi recorded net earnings of $0.3 million and $6.9 million. Earnings were adversely affected by non-cash items such as depletion, depreciation, accretion, stock-based compensation and future income taxes.

cash netbacks ($/boe)

netback analysis

	Three Months Ended December 31			*Twelve Months Ended December 31*		
	2006	*2005*	*% Change*	*2006*	*2005*	*% Change*
Barrels of oil equivalent ($/boe)						
Realized sales price	***50.02***	*64.94*	*(23)*	***49.36***	*52.48*	*(6)*
Royalties, net of ARTC	***6.13***	*14.68*	*(58)*	***7.20***	*10.60*	*(32)*
Operating expenses	***8.42***	*7.90*	*7*	***8.29***	*8.46*	*(2)*
Transportation	***3.55***	*3.18*	*12*	***3.38***	*3.18*	*6*
Operating netback	***31.92***	*39.18*	*(19)*	***30.49***	*30.24*	*1*
G&A	***1.72***	*0.95*	*81*	***1.24***	*1.62*	*(23)*
Interest	***4.42***	*1.98*	*123*	***3.28***	*2.37*	*38*
Current taxes	–	*0.11*	*(100)*	–	*0.16*	*(100)*
Cash netback	***25.78***	*36.14*	*(29)*	***25.97***	*26.09*	–
Unrealized (gain)/loss on financial contracts	***(0.76)***	*(5.94)*	*(87)*	***(0.52)***	*0.42*	–
Stock-based compensation expense	***0.69***	*0.86*	*(20)*	***1.31***	*1.06*	*24*
Depletion, depreciation and accretion	***24.58***	*19.05*	*29*	***21.15***	*17.59*	*20*
Future income taxes (recovery)	***0.64***	*7.77*	*(92)*	***0.41***	*2.70*	*(85)*
Net earnings	***0.63***	*14.40*	*(96)*	***3.62***	*4.32*	*(16)*

Approximately 82 percent of Delphi's production is natural gas and therefore Delphi's netbacks are primarily driven by the price received for natural gas. Delphi has an active risk management program to mitigate some of the volatility in commodity prices. During the Quarter cash netbacks increased 10 percent from the third quarter of 2006 due to increased operating netbacks per boe (increased $3.83/boe or 13 percent) offset by an increase in G&A per boe ($0.65/boe or 60 percent) and interest per boe ($0.68/boe or 18 percent).

drilling results

	Twelve Months Ended December 31	
	Gross	*Net*
Natural gas wells	*43.0*	*19.0*
Oil wells	*1.0*	*0.6*
Dry holes	*8.0*	*2.1*
Total wells	*52.0*	*21.7*
Success rate (%)	*85*	*90*

The Company had a successful year with the drill bit resulting in a drilling success rate of 90 percent. The Company has in excess of 100 drilling locations identified within its core areas of operations.

capital invested

	2006	Three Months Ended December 31 2005	% Change	2006	Twelve Months Ended December 31 2005	% Change
Land	535	107	400	3,578	242	1,379
Seismic	–	17	(100)	10,070	103	9,677
Drilling and completions	3,544	19,618	(82)	86,473	37,187	133
Equipping and facilities	7,646	8,974	(15)	62,137	22,299	179
Property and corporate acquisition	–	(94)	(100)	1,188	51,273	(98)
Capitalized expenses	368	352	5	1,825	1,187	54
Other	31	82	(62)	81	177	(54)
Capital invested	12,124	29,056	(58)	165,352	112,468	47
Asset retirement costs (net of dispositions)	(40)	1,071	–	423	2,469	(83)
Total capital invested	12,084	30,127	(60)	165,775	114,937	44

In 2006, Delphi incurred record capital gross expenditures of $165.3 million and disposed of non-core, low working interest properties for approximately $34.9 million resulting in net capital expenditures of $130.4 million. Approximately 55 percent of Delphi's gross capital was allocated to the farm-in at Bigfoot in North East British Columbia which included $40 million in non-recurring infrastructure costs and seismic. Delphi spent approximately $86.5 million participating in the drilling of 52 wells (21.7 net). Delphi incurred $49.1 million drilling 16 wells in Bigfoot paying 90 percent of the costs to earn a 50 percent working interest in the wells. Delphi has satisfied the terms of the Bigfoot farm-in and will participate on a 50/50 basis going forward. The remaining capital was spent on Delphi's core properties in North West Alberta and North East British Columbia, specifically, a major field infrastructure expansion including eight kilometres of new natural gas pipelines and expansion of a field compression facility and the acquisition of undeveloped sections of land in Delphi's core areas.

liquidity and capital resources

Funding

	Three Months Ended December 31	Twelve Months Ended December 31
Sources:		
Funds from operations	11,817	49,551
Issue of shares	–	305
Issue of flow-through shares	–	25,003
Property dispositions	17,867	34,918
	29,684	109,777
Uses:		
Cash	757	757
Share issue costs	–	1,725
Capital expenditures	12,124	165,352
Expenditures on site restoration and reclamation	98	503
Change in non-cash working capital	23,416	14,740
	36,395	183,077
Increase in bank debt	6,711	73,300

For the three and 12 months ended December 31, 2006, Delphi funded its capital program through a combination of cash flow, debt, property dispositions and the issuance of flow-through common shares.

Share Capital

At December 31, 2006, the Company had 60.7 million common shares outstanding (December 31, 2005 – 55.3 million). The common shares of Delphi trade on the TSX under the symbol DEE. The following table summarizes outstanding share data for the three and 12 months ended December 31, 2006.

	Three Months Ended December 31	Twelve Months Ended December 31
Weighted Average Common Shares		
Basic	60,662	58,051
Diluted	61,584	58,84
Trading Statistics [1]		
High	$ 3.49	$ 5.82
Low	$ 2.39	$ 2.39
Average daily volume	247,245	148,242

Trading statistics based on closing price.

[illegible] at March 6, 2007, the Company had 68.0 million common shares outstanding and 4.2 million stock options outstanding.

bank debt plus working capital deficit

At December 31, 2006, the Company had $115.0 million outstanding on its credit facility and a working capital deficit of $3.2 million for total debt plus working capital deficit of $118.2 million excluding the financial asset of $0.3 relating to the unrealized gain on financial commodity contracts. Subsequent to year-end, Delphi issued 7.35 million flow-through common shares at a price of $2.45 per share for gross proceeds of $18.0 million. Delphi anticipates spending projected funds from operations on capital expenditures during 2007.

The capital intensive nature of the industry will generally result in the Company having a working capital deficit. The Company has a [illegible] facility for $115.0 million with a syndicate of Canadian chartered banks. The facility is a 364 day committed revolving facility [illegible]th a one year term out provision. The credit facility bears interest based on a sliding scale tied to the Company's trailing debt to funds flow from operations: from a minimum of the bank's prime rate to a maximum of the bank's prime rate plus 1.0 percent. In addition to the revolving term facility, the Company has a $10.0 million development facility with its lenders to fund the Bigfoot joint venture. The pricing grid on the development facility is 0.25 percent higher than the revolving term facility.

financial strategy

The Company maintains an active risk management program as an integral part of its overall financial strategy to mitigate cash flow volatility resulting from fluctuating commodity prices. Delphi's risk management program consists of both fixed price contracts as well as costless collars, which provide both downside protection and the opportunity to share in the upside if market prices move above the floor price. Currently, Delphi is in the enviable position of having hedged approximately 55 percent of its before-royalty gas production at an average AECO floor price of $8.96 per thousand cubic feet from January 1, 2007 to March 31, 2008. The active risk management program allows the Company to maintain a capital program throughout the first six months of 2007 without an increase in debt levels. The Company is committed to lowering its debt level in 2007 and will minimize the use of leverage in the year with projected debt at the end of the second quarter to be approximately $100.0 million. The Company plans to spend the majority of its capital during the second half of the year, timed with an expected stronger natural gas environment and lower cost of services.

selected quarterly information

The following table sets forth certain information of the Company for the past eight consecutive quarters.

	Dec. 31 2006	Sept. 30 2006	Jun. 30 2006	Mar. 31 2006	Dec. 31 2005	Sept. 30 2005	Jun. 30 2005	Mar. 31 2005
Production								
Oil and NGLs (bbl/d)	829	856	1,034	1,062	1,028	889	865	872
Natural gas (mcf/d)	24,919	25,403	28,797	23,695	22,909	19,580	19,961	16,880
Barrels of oil equivalent (boe/d)	4,982	5,090	5,834	5,011	4,846	4,152	4,192	3,685
Financial ($000s, except as noted)								
Petroleum and natural gas revenue	22,928	21,587	25,865	23,809	28,961	20,606	17,335	13,978
Funds from operations	11,817	10,902	14,452	12,380	16,118	10,199	7,937	5,958
Per share - Basic	0.19	0.18	0.26	0.22	0.31	0.20	0.16	0.12
Per share - Diluted	0.19	0.18	0.26	0.22	0.31	0.20	0.16	0.12
Net earnings (loss)	290	658	4,768	1,187	6,425	1,190	1,004	(1,942)
Per share - Basic	–	0.01	0.09	0.02	0.13	0.02	0.02	(0.04)
Per share - Diluted	–	0.01	0.09	0.02	0.12	0.02	0.02	(0.04)
Capital invested	12,124	27,886	44,313	81,029	29,056	16,280	7,096	60,036
Dispositions	(17,867)	(1,331)	(15,720)	–	–	–	–	(5,862)
Net capital expenditures	(5,743)	26,555	28,593	81,029	29,056	16,280	7,096	54,174
Per unit information								
Natural gas ($/mcf)	8.41	7.20	7.59	8.54	11.69	9.30	7.80	7.28
Oil and natural gas liquids ($/bbl)	48.39	61.10	63.43	46.79	45.70	47.15	40.35	37.16
Oil equivalent ($/boe)	50.02	46.10	48.72	52.79	64.94	53.95	45.45	42.13
Operating netback ($/boe)	31.92	27.61	31.28	30.55	39.18	31.17	24.45	23.83

contractual obligations

The Company is committed, under contracts of varying lengths, for the utilization of gathering, processing and pipeline capacity on a major natural gas processing and gathering system in North East British Columbia. The future minimum commitments are as follows:

2007	$	3,898
2008		3,190
2009		2,992
2010		3,241
2011		2,535
2012 – 2015		6,995

As at December 31, 2006, the Company had incurred the necessary qualifying exploration expenditures to satisfy the terms of the flow-through shares issued in 2005. Although the Company believes it has incurred the necessary qualifying expenditures, these amounts may be subject to audit and subsequent interpretation by the Canada Revenue Agency. The Company has an obligation to incur qualifying exploration expenditures of $25.0 million by December 31, 2007 to satisfy the terms of the flow-through common shares issued during 2006.

guarantees and off-balance sheet arrangements

Delphi has not entered into any off-balance sheet arrangements or guarantees.

business conditions and risk

[illegible] business of exploration, development and acquisition of oil and gas reserves involves a number of [illegible]ncertainties and as a result the Company is exposed to certain business risks inherent in the oil and [illegible] industry which affect results. These business risks can generally be grouped into two major areas: [illegible]erations, including environmental, and financial.

[illegible]ationally, the Company faces risks associated with finding, developing and producing oil and gas [illegible]erves. The Company attempts to control operating risks by maintaining a disciplined approach to [illegible]nentation of the exploration and development program. Exploration risks are managed by hiring [illegible]enced technical staff and by concentrating the exploration activity on specific core regions where [illegible] Company has experience and expertise. The Company also attempts to operate associated projects [illegible] its level of ownership is sufficient. Operational control allows the Company to manage costs, timing [illegible] sales of production.

[illegible] of economically recoverable reserves and the future net cash flow they will generate are based [illegible]umber of factors and assumptions, such as commodity prices, projected production and future [illegible]and operating costs. All of these estimates may vary from actual results. The Company has its [illegible] evaluated annually by an independent engineering firm and reviews their findings with the Audit [illegible]tee of the Board of Directors.

[illegible]ental risks are also associated with field operations. The Company has health and safety programs [illegible]ures and an environmental standards policy. These policies and procedures are designed to [illegible] maintain the environment with respect to all Company operations. The Company performs an [illegible] party audit of the safety and environmental policies designed to ensure compliance. Delphi [illegible]ronmental liability, property, drilling and general liability insurance in amounts considered [illegible]ndards.

[illegible]ny is also exposed to financial risks in the form of commodity prices, interest rates, the [illegible] U.S. dollar exchange rate and inflation. Delphi manages commodity price risks by focusing [illegible]rogram on areas that are expected to generate attractive rates of return even at substantially [illegible]odity prices than the industry is currently receiving. The Company also conducts a commodity [illegible]agement program designed to mitigate large downward movements in commodity prices.

[illegible]ompany's 2006 Annual Information Form (AIF) for a further listing of risks.

[illegible]l accounting estimates

[illegible] financial statements have been prepared in accordance with Canadian general accepted [illegible]ounting principles. Certain accounting policies require management to make decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. Delphi's management review their estimates frequently; however, the emergence of new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates. Delphi attempts to mitigate this risk by employing individuals with the appropriate skill set and knowledge to make reasonable estimates; developing internal reporting systems; and comparing past estimates to actual results.

The Company's financial and operating results include estimates of the following:

- Depletion, depreciation and accretion based on estimates of oil and gas reserves;
- Estimated revenues, operating expenses and royalties for which actual revenues and costs have not been received;
- Estimated capital expenditures on projects that are in progress;
- Estimated fair value of derivative contracts;
- Estimated amount of the asset retirement obligation including estimates of future costs and the timing of the costs; and
- Estimated fair value of the Company in performing the goodwill impairment test.

future accounting pronouncements

In January 2005, the CICA issued Handbook section 3855, Financial Instruments – Recognition and Measurement, Handbook section 3865, Hedges and Handbook section 1530, Comprehensive Income.

Section 3855 establishes standards for the recognition and measurement of financial assets, financial liabilities and non-financial derivatives. The standard specifies when and to which amount a financial instrument is to be recorded on the balance sheet. Financial instruments are to be recorded at fair value in some cases and at cost in others. The section also provides guidance for disclosure of gains and losses on financial instruments.

Section 3865 includes and replaces the guidance on hedging relationships that was previously contained in AcG-13,mostly those relating to the designation of hedging relationships and its documentation. The new standard specifies how to apply hedge accounting and which information has to be disclosed by the entity.

Section 1530 establishes standards for the reporting and presentation of comprehensive income. Comprehensive income includes net income as well as all changes in equity during a period, from transactions and events from non-owner sources. Comprehensive income and its components should be presented in a financial statement with the same prominence as other financial statements.

These sections are to be applied to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2006. The Company is currently evaluating the impact of these new standards.

corporate governance

Overview

The shareholders' interests are a critical factor in the operation and management of Delphi. The Company is committed to maintaining the highest level of investor confidence in the Company through the development of its corporate governance polices. Delphi's Board consists of five independent directors and two officers of the Company who meet regularly to discuss matters of strategy and execution of the business plan. See Delphi's AIF for a listing of committees who oversee specific aspects of the Company's operating and financial strategy.

The application of Bill 198 and its regulations represents an exercise in continuous improvement, which is leading the Company to formalize processes and control measures that are already in place and to introduce new ones. Delphi has chosen to make this a strategic endeavour, which will result in operational improvements and better management.

Disclosure Controls

eginning in 2005, the Company was required to issue a "Modified Certification of Annual Filings during ransition Period" (Modified Certification) in accordance with Multilateral Instrument 52-109, Certification Disclosures in Issuers' Annual and Interim Filings. The Modified Certification requires certifying officers state that they are responsible for establishing and maintaining disclosure controls and procedures nd as such have designed such procedures and evaluated their effectiveness as of the end of the period ed by the annual filings. Management believes the disclosure controls and procedures provide a sonable level of assurance that information required to be disclosed by the Company is recorded, cessed, summarized and reported within the time periods specified and the controls and procedures signed to ensure that information required to be disclosed by the Company is accumulated and mmunicated to the issuer's management, including its Chief Executive Officer and Chief Financial appropriate to allow timely decisions regarding required disclosure. The Company notes that believes the disclosure controls and procedures provide a reasonable level of assurance that they ctive, it does not expect that the disclosure controls and procedures will prevent all errors and control system is designed to provide reasonable, not absolute, assurance that the objectives of trol system are met.

Controls Over Financial Reporting

2006, Canadian Securities Administrators decided not to proceed with proposed Multilateral ent 52-111 Reporting on Internal Control over Financial Reporting and instead proposed to expand ral Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings. The major sulting from this are that the CEO and CFO will be required to certify in the annual certificates have evaluated the effectiveness of internal controls over financial reporting ("ICOFR") as of the ancial year and disclose in the annual MD&A their conclusions about the effectiveness of e will be no requirement to obtain an internal control audit opinion from the issuer's auditors management's assessment of the effectiveness of ICOFR. This proposed amendment is to apply for the year ended December 31, 2008. Delphi is continuing with its evaluation of nsure it meets the criteria for the proposed certification for December 31, 2008.

's President and Chief Executive Officer and Vice President, Finance and Chief Financial there have been no changes in the Company's internal control over financial reporting during the most recent interim period that has materially affected, or is reasonably likely to , the Company's internal control over financial reporting.

sizes a full-cycle approach to its business and strives for internally generated development as a means of enhancing its production base and ultimately creating value for shareholders. is to become a dominant natural gas developer and explorer focused in North East Columbia and North West Alberta. The objective is to develop an inventory of opportunities undeveloped land base so that production and reserves can be added independent of acquisition activity. In that regard, the Company's ability to add production through the drill bit creates a competitive advantage over those competitors that are reliant upon acquisitions to build or maintain their production base. Currently, Delphi has identified over 100 drilling locations on in its core areas. Delphi will also continue to pursue acquisitions that will be accretive on a per share basis to cash flow, production, reserves, net asset value and provide significant development opportunities to further enhance value. Delphi believes the long-term fundamentals support strong commodity prices, particularly in natural gas, despite the recent price volatility.

2007 Capital Investment and Development Activities

The capital program for 2007 is estimated to be $45 - $50 million, dependent on both field service costs and commodity prices. The Company plans to spend the majority of its capital during the second half of the year, timed with an expected stronger natural gas price environment and lower cost of services. During the near-term period of potentially volatile natural gas prices due to the continued excess of natural gas in storage, the drilling program will favor the Company's oil projects with spending on Delphi's natural gas projects focused on robust capital efficient well recompletions and optimization projects. Delphi's exploration program which requires longer lead-times and targets natural gas will continue with the view of a natural gas price recovery into 2008.

2007 Production Volumes

The production outlook for 2007 will be principally affected by the on-stream timing of new production, availability of drilling rigs, service rigs, other oil field services and anticipated drilling activity. Delphi expects to average approximately 5,200 to 5,400 boe/d with an exit rate of approximately 5,700 boe/d.

Sensitivities

The following table provides projected estimates for 2007 of the sensitivity of the Company's funds flow from operations to changes in a number of variables:

	Funds Flow		*Net Earnings*	
	Amount	*Per share*	*Amount*	*Per share*
Change of 1.0 mmcf/d in natural gas production	1,500	0.02	100	–
Change of $1.00 per mcf in average gas price	3,500	0.05	2,300	0.03
Change of 1 percent in interest rates	250	–	160	–

SEDAR filing

Additional information about Delphi is available on the Canadian Securities Administrators' System for Electronic Document Analysis and Retrieval (SEDAR) at www.sedar.com and at the Company's website at www.delphienergy.ca.

management's report

The financial statements of Delphi Energy Corp. were prepared by management in accordance with Canadian generally accepted accounting principles. The financial and operating information presented in this annual report is consistent with that shown in the financial statements. Management has designed and maintains a system of internal controls to provide reasonable assurance that all assets are safeguarded and to facilitate the preparation of financial statements for reporting purposes. Timely release of financial information sometimes necessitates the use of estimates when transactions affecting the current :counting period cannot be finalized until future periods. Such estimates are based on careful judgments made by management. External auditors appointed by the shareholders have conducted an independent examination of the Company's accounting records in order to express their opinion on the financial statements. The Board of Directors is responsible for ensuring that management fulfils its responsibilities for financial and internal control. The Board exercises this responsibility through its Audit and Reserves mmittee. The Audit and Reserves Committee, which consists of non-management members, has met with the external auditors and management in order to determine that management has fulfilled s responsibilities in the preparation of the financial statements. The Audit and Reserves Committee has ›rted its findings to the Board of Directors who have approved the financial statements.

David J. Reid	*Brian P. Kohlhammer*
sident and Chief Executive Officer	*Vice President Finance and Chief Financial Officer*
ıary, Canada	
h 6, 2007	

›uditors' report to the shareholders

› audited the consolidated balance sheets of Delphi Energy Corp. as at December 31, 2006 and nd the consolidated statements of earnings and retained earnings and cash flows for the years then These consolidated financial statements are the responsibility of the Company's management. Our ibility is to express an opinion on these consolidated financial statements based on our audits.

ted our audits in accordance with Canadian generally accepted auditing standards. Those ·equire that we plan and perform an audit to obtain reasonable assurance whether the financial are free of material misstatement. An audit includes examining, on a test basis, evidence ·ting the amounts and disclosures in the financial statements. An audit also includes assessing the principles used and significant estimates made by management, as well as evaluating the inancial statement presentation.

›ur opinion, these consolidated financial statements present fairly, in all material respects, the financial osition of the Company as at December 31, 2006 and 2005 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants

Calgary, Canada

March 6, 2007

consolidated balance sheets

As at December 31
(CDN$ thousands)

	2006	2005
Assets		
Current assets:		
Cash	757	–
Accounts receivable	16,097	17,907
Prepaid expenses and deposits	1,460	11,170
Risk management asset	348	–
	18,662	29,077
Property, plant and equipment (Note 4)	295,906	203,489
Goodwill	12,100	12,100
Total assets	326,668	244,666
Liabilities		
Current liabilities:		
Accounts payable and accrued liabilities	21,492	47,752
Risk management liability	–	645
Bank debt (Note 5)	–	41,700
	21,492	90,097
Long-term debt (Note 5)	115,000	–
Future income taxes (Note 8)	23,776	14,292
Asset retirement obligations (Note 6)	7,951	7,394
Total liabilities	168,219	111,783
Shareholders' equity		
Share capital (Note 7)	139,108	123,692
Contributed surplus (Note 7)	5,627	2,380
Retained earnings	13,714	6,811
Total shareholders' equity	158,449	132,883
Total liabilities and shareholders' equity	326,668	244,666

Contractual obligations and commitments (Note 10)

Subsequent event (Note 13)

See accompanying notes to the consolidated financial statements.

Approved by the Board,

H.R. Lawrie

Henry R. Lawrie
Director

L. Tolley

Lamont C. Tolley
Director

consolidated statements of earnings and retained earnings

r the years ended December 31

$ thousands, except per share amounts)	*2006*	*2005*
nue:		
Petroleum and natural gas sales	*94,374*	*83,764*
alized loss on risk management activities	*(185)*	*(2,884)*
	94,189	*80,880*
Royalties (net of Alberta royalty tax credit)	*(13,731)*	*(16,335)*
ealized gain/(loss) on risk management activities	*993*	*(645)*
	81,451	*63,900*
rating	*15,826*	*13,041*
sportation	*6,455*	*4,893*
neral and administrative	*2,372*	*2,491*
k-based compensation (Note 7)	*2,491*	*1,631*
st	*6,254*	*3,658*
tion, depreciation and accretion	*40,364*	*27,094*
	73,762	*52,808*
before taxes	*7,689*	*11,092*
	–	*250*
	786	*4,165*
	786	*4,415*
	6,903	*6,677*
gs, beginning of year	*6,811*	*134*
s, end of year	*13,714*	*6,811*
gs per share (Note 7)		
	0.12	*0.13*
	0.12	*0.13*

e accompanying notes to the consolidated financial statements.

consolidated statements of cash flows

For the years ended December 31 (CDN$ thousands)	2006	2005
Cash flow from operating activities		
Net earnings	6,903	6,677
Add non cash items:		
Depletion, depreciation and accretion	40,364	27,094
Stock-based compensation	2,491	1,631
Unrealized loss/(gain) on risk management activities	(993)	645
Future taxes	786	4,165
Expenditures on site restoration and reclamation	(503)	(613)
Change in non-cash working capital (Note 11)	3,102	3,167
	52,150	42,766
Cash flow from financing activities		
Issue of shares, net of issue costs	23,583	37,906
Decrease in mezzanine debt	–	(10,000)
Increase (decrease) in bank debt	73,300	(5,700)
	96,883	22,206
Cash flow used in investing activities		
Capital expenditures	(165,352)	(61,195)
Acquisition of petroleum and natural gas properties	–	(51,273)
Proceeds on the disposition of properties	34,918	5,862
Change in non-cash working capital (Note 11)	(17,842)	9,742
	(148,276)	(96,864)
Increase in cash and cash equivalents	757	(31,892)
Cash and cash equivalents, beginning of year	–	31,892
Cash and cash equivalents, end of year	757	–
Interest paid	5,585	3,387
Taxes paid	220	239

See accompanying notes to the consolidated financial statements.

notes to consolidated financial statements

as at and for the years ended december 31, 2006 and 2005

(all tabular amounts are expressed in thousands of CDN dollars, except per unit amounts)

note 1: description of business

Delphi Energy Corp. ("the Company" or "Delphi") is incorporated under the Business Corporations Act (Alberta) and is a public company listed on the Toronto Stock Exchange. Delphi is primarily engaged in the exploration for and development and production of natural gas properties located in North West Alberta and North East British Columbia and crude oil properties in East Central Alberta.

note 2: significant accounting policies

The consolidated financial statements of Delphi have been prepared by management in accordance with accounting principles generally accepted in Canada. The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reported period. Actual results may differ from these estimates.

(a) Principles of consolidation:

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries. Any reference to the Company refers to the Company and its subsidiaries. All inter-company transactions have been eliminated.

Petroleum and natural gas operations:

The Company follows the full cost method of accounting whereby all costs associated with the exploration for and development of petroleum and natural gas reserves are capitalized. Such costs include land acquisition costs, geological and geophysical costs, lease rental costs on non-producing properties, costs of both productive and unproductive drilling and production equipment. Gains or losses are not recognized upon disposition of petroleum and natural gas properties unless crediting the proceeds against accumulated costs would result in a change in the depletion rate of 20 percent or more.

The accumulated costs, less the costs of acquisition of unproved properties, are depleted using the unit-of-production method based upon total proved reserves before royalties as determined by independent evaluators. Natural gas reserves and production are converted into equivalent barrels of oil at 6:1 based upon the estimated relative energy content.

The costs of acquiring and evaluating unproved properties are initially excluded from depletion calculations. These properties are assessed periodically to ascertain whether impairment has occurred. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of impairment is added to the costs subject to depletion.

The Company is required to perform a ceiling test at least annually to assess the carrying value of oil and gas assets. The costs are assessed to be recoverable if the sum of the undiscounted cash flows expected from the production of proved reserves using forecast prices and the lower of cost and market of unproved properties exceed the carrying value of the petroleum and natural gas assets. If the carrying amount of the petroleum and natural gas assets is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value exceeds the sum of the discounted cash flows expected

from the production of proved and probable reserves and the lower of cost and market of unproved properties. This approach incorporates risks and uncertainties in the expected future cash flows, which are discounted using a risk free rate.

Depreciation of furniture and office equipment is provided using the declining balance method based upon estimated useful lives of 20 percent to 50 percent.

(c) Interest in joint ventures:

Substantially all of the Company's exploration, development and production activities are conducted jointly with others and the financial statements reflect the Company's proportionate interest in such activities.

(d) Goodwill:

Goodwill, at the time of acquisition, represents the excess of purchase price of a business over the fair value of net assets acquired. Goodwill is assessed by the Company for impairment at least each year end. If the fair value of the business is less than the book value, a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the business' assets and liabilities from the fair value of the business to determine the implied fair value of goodwill and comparing that amount to the book value of goodwill. Any excess of the book value of goodwill over the implied fair value is the impairment amount and will be charged to income in the period of the impairment.

(e) Asset retirement obligations:

The Company recognizes the fair value of an asset retirement obligation as a liability at the time it incurs a legal obligation for the future abandonment and reclamation costs associated with its petroleum and natural gas operations. Asset retirement obligations are initially measured at their fair value and subsequently adjusted to reflect the passage of time (accretion) and any changes to the estimated cash flows underlying the obligation. The associated asset retirement cost is capitalized as part of property, plant and equipment and amortized to earnings using the unit of production method over estimated proved reserves consistent with the depletion and depreciation of the underlying asset.

(f) Stock-based compensation:

The Company records a compensation cost for all stock options granted to employees, directors or key consultants over the vesting period of the options based on the fair value method. The compensation cost is a charge to earnings or capitalized as a cost of exploration and development activities with an offsetting increase to contributed surplus on the balance sheet. Consideration paid by employees, directors or key consultants upon exercise of the stock options and the amount previously recognized in contributed surplus are recorded as share capital. The Company has not incorporated an estimated forfeiture rate for stock options that will not vest, rather, the Company accounts for actual forfeitures as they occur.

(g) Future income taxes:

The Company follows the tax liability method of accounting for income taxes. Under this method, estimated future income tax assets and liabilities are determined based upon differences between the carrying amount as reported on the balance sheet and the tax basis of assets and liabilities and measured

using substantively enacted tax rates and laws expected to be in effect when the differences are expected to reverse. The effect on future tax assets and liabilities of a change in tax rates is recognized in earnings in the period in which the change occurs. A valuation allowance is recognized against any future income tax assets if it is considered more likely than not that the asset will not be realized.

(h) Flow-through shares:

The resource expenditure deductions for income tax purposes related to exploration and development activities funded by flow-through share arrangements are renounced to investors in accordance with income tax legislation. To recognize the foregone tax benefits to the Company, the future income tax liability and share capital are adjusted by the estimated cost of the renounced tax deduction on the date of renouncement.

(i) Per share information:

Basic per share amounts are computed by dividing the net earnings by the weighted average number of common shares outstanding for the year. Diluted per share amounts reflect the potential dilution that would occur if securities or other contracts to issue common shares were exercised or converted to common shares. Diluted per share information is calculated using the treasury stock method that assumes any proceeds received by the Company upon the exercise of in-the-money stock options, plus the unamortized stock based compensation cost, would be used to buy back common shares at the average market price for the period. Anti-dilutive options or instruments are not included in the calculation.

(j) Financial instruments:

Financial instruments consist primarily of accounts receivable, prepaid expenses, accounts payable and accrued liabilities and bank debt. There are no significant differences between the carrying value of these instruments and their estimated fair value.

The Company uses financial instruments for non-trading purposes to manage fluctuations in commodity prices, as described in Note 9. The Company has elected to mark-to-market its financial contracts.

(k) Measurement uncertainty:

The amounts recorded for depletion and depreciation of petroleum and natural gas properties and equipment are based upon estimates of proved petroleum and natural gas reserves, production rates, commodity prices and future costs. The impairment test is based upon estimates of proved and, if applicable, probable reserves, production rates, petroleum and natural gas prices, future costs and other assumptions. The asset retirement obligations are based upon petroleum and natural gas reserves, future costs, expected inflation rates and other assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes to estimates in future periods could be material.

(l) Cash and cash equivalents:

The Company considers deposits in banks, certificates of deposit and short-term investments with original maturities of three months or less and cash in trust as cash and cash equivalents. Bank borrowings are considered to be financing activities.

(m) Revenue recognition:

Crude oil and natural gas revenues are recognized in earnings when title passes from the Company to its customer.

note 3: acquisitions

On February 1, 2005, the Company acquired producing natural gas and natural gas liquids properties with associated facilities and undeveloped land for cash consideration of $51.3 million. The Company paid for the acquisition with cash and increased bank debt.

note 4: property, plant and equipment

As at December 31, 2006		*Cost*		*Accumulated depletion and depreciation*		*Net book value*
Petroleum and natural gas properties	$	285,168	$	71,331	$	213,837
Production equipment		95,892		14,087		81,805
Furniture, fixtures and office equipment		639		375		264
	$	381,699	$	85,793	$	295,906
As at December 31, 2005						
Petroleum and natural gas properties	$	203,264	$	38,035	$	165,229
Production equipment		45,763		7,744		38,019
Furniture, fixtures and office equipment		527		286		241
	$	249,554	$	46,065	$	203,489

As at December 31, 2006, costs in the amount of $35.8 million (December 31, 2005 - $18.9 million) representing unproved properties were excluded from the depletion calculation and estimated future development costs of $21.7 million (December 31, 2005 - $9.6 million) have been included in costs subject to depletion. All costs of unproved properties have been capitalized. Ultimate recoverability of these costs will be dependent upon finding proved oil and natural gas reserves. The Company performed a separate impairment review of assets excluded from the ceiling test and determined that no impairment has occurred.

The Company capitalized $1.8 million (December, 2005 - $1.2 million) of general and administrative costs directly related to exploration and development activities.

The Company performed a ceiling test calculation at December 31, 2006 to assess the recoverable value of property, plant and equipment, which indicated no write down was required. The future commodity prices used in the impairment test were based on December 31, 2006 commodity price forecasts of the Company's independent reserve engineers adjusted for differentials specific to the Company's reserves. The following table summarizes the future benchmark prices the Company used in the impairment test.

	Natural Gas		Natural Gas Liquids			Crude Oil		
	NYMEX Futures Contract (US$/mmbtu)	AECO Spot (CDN$/mmbtu)	Propane (CDN$/bbl)	Butane (CDN$/bbl)	Pentanes Plus (CDN$/bbl)	West Texas Intermediate (US$/bbl)	Edmonton Light (CDN$/bbl)	Bow River Hardisty (CDN$/bbl)
2007	7.25	7.20	45.00	56.25	71.75	62.00	70.25	49.00
2008	7.50	7.45	43.50	50.25	69.25	60.00	68.00	49.00
2009	7.50	7.75	42.00	48.75	67.00	58.00	65.75	48.75
2010	7.50	7.80	41.25	47.75	65.75	57.00	64.50	48.25
2011	7.50	7.85	41.25	47.75	65.75	57.00	64.50	49.00
2012	7.75	8.15	41.50	48.00	66.25	57.50	65.00	49.50
2013	7.90	8.30	42.50	49.00	67.50	58.50	66.25	50.25
2014	8.05	8.50	43.25	50.25	69.00	59.75	67.75	51.50
2015	8.20	8.70	44.25	51.00	70.50	61.00	69.00	52.50
2016	8.40	8.90	45.00	52.25	72.00	62.25	70.50	53.50
2017	8.55	9.10	46.00	53.00	73.25	63.50	71.75	54.50
Thereafter [1]								

A percentage increase of 2% represents the change in future prices each year after 2017 to the end of the reserve life.

note 5: long term debt and bank debt

The Company has a revolving facility for $115.0 million with a syndicate of Canadian chartered banks. The facility is a 364 day committed revolving facility with a one year term out provision. The current structure of the lending facility is such that amounts outstanding are recognized as a long-term liability. The previous lending agreement was a demand facility and accordingly was classified as a current liability. The credit facility bears interest based on a sliding scale tied to the Company's trailing debt to cash flow: from a minimum of the bank's prime rate to a maximum of the bank's prime rate plus 1.0 percent.

In addition to the revolving term facility, the Company has a $10.0 million development facility with its lenders to fund the Bigfoot joint venture. The pricing grid on the development facility is 0.25 percent higher than the revolving term facility.

The two facilities are secured by a $150.0 million demand floating charge debenture and a general security agreement over all assets of the Company.

note 6: asset retirement obligations

The Company's asset retirement obligations result from working interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The Company estimates the total undiscounted amount of cash flows required to settle its asset retirement obligations, over the next three to 20 years, is approximately $16.9 million. A credit-adjusted risk-free rate of 8.0 percent and an inflation rate of 2.5 percent were used to calculate the estimated fair value of the asset retirement obligations.

A reconciliation of the asset retirement obligations is provided below.

As at December 31		*2006*		*2005*
Balance, beginning of year	$	7,394	$	5,012
Liabilities incurred		606		950
Liabilities sold		(183)		(250)
Liabilities acquired		–		1,604
Liabilities settled		(503)		(613)
Change in estimate		–		165
Accretion expense		637		526
Balance, end of year	$	7,951	$	7,394

note 7: share capital

(a) Authorized:

An unlimited number of voting common shares.

An unlimited number of preferred shares issuable in series.

(b) Common shares issued:

As at December 31	*2006*			*2005*		
	Outstanding shares (000s)		*Amount*	*Outstanding shares (000s)*		*Amount*
Balance, beginning of year	55,254	$	123,692	47,704	$	87,944
Issue of flow-through common shares	5,209		25,003	4,686		26,004
Issue of common shares	–		–	2,500		14,000
Exercise of stock options	200		305	364		643
Allocated from contributed surplus	–		145	–		323
Share issue costs	–		(1,725)	–		(2,741)
Future tax effect of share issue costs	–		528	–		921
Tax benefit renounced to shareholders	–		(8,840)	–		(3,402)
Balance, end of year	60,663	$	139,108	55,254	$	123,692

On June 29, 2006, the Company issued 5.2 million flow-through common shares at a price of $4.80 per share for gross proceeds of $25.0 million.

On December 29, 2005, the Company issued 2.5 million common shares at a price of $5.60 per share for gross proceeds of $14.0 million.

On December 13, 2005, the Company issued 1.96 million flow-through common shares at a price of $7.15 per share for gross proceeds of $14.0 million.

On March 31, 2005, the Company issued 2.7 million flow-through common shares at a price of $4.40 per share for gross proceeds of $12.0 million.

As at December 31, 2006, the Company had incurred the necessary qualifying exploration expenditures to satisfy the terms of the flow-through shares issued in 2005. Although the Company believes it has incurred the necessary qualifying expenditures, these amounts may be subject to audit and subsequent interpretation by the Canada Revenue Agency. The Company has an obligation to incur qualifying exploration expenditures of $25.0 million by December 31, 2007, to satisfy the terms of the flow-through common shares issued during 2006.

(c) Stock options:

The Company has established a stock option plan under which it has granted options to acquire common shares to certain officers, directors, employees and key consultants. The plan provides for the granting of options equal to 10 percent of the issued and outstanding common shares of the Company. Options issued under the plan have a term of five years to expiry and vest over a two-year period starting on the date of the grant. The exercise price of each option equals the closing market price of the Company's common shares immediately preceding the date of the grant. As at December 31, 2006 there were 4.2 million options to purchase shares outstanding.

The following table summarizes the changes in the number of options outstanding and the weighted average share prices.

As at December 31	2006		2005	
	Outstanding options (000's)	Weighted average exercise price	Outstanding options (000's)	Weighted average exercise price
Balance, beginning of year	2,629	$ 2.37	1,895	$ 1.59
Granted	1,800	4.69	1,165	3.43
Exercised	(200)	1.53	(364)	1.77
Cancelled	–	–	(67)	1.85
Balance, end of year	4,229	3.40	2,629	2.37
Exercisable at end of year	2,641	$ 2.81	1,755	$ 1.90

The following table summarizes information about the stock options outstanding and exercisable at December 31, 2006.

	Options outstanding			Options exercisable	
Range of exercise price	Outstanding options (000's)	Weighted average exercise price	Weighted average remaining term	Exercisable (000's)	Weighted average Exercise price
$0.99	343	$ 0.99	1.2	343	$ 0.99
$1.45 - 1.61	694	1.46	1.5	694	1.46
$1.75 - 1.90	27	1.80	2.6	27	1.80
$2.66	200	2.66	2.9	200	2.66
$3.25 - $3.99	1,190	3.35	3.2	785	3.39
$4.44 - $4.70	1,635	4.65	4.2	545	4.65
$5.11 - $5.39	140	5.31	4.1	47	5.31
Total	4,229	$ 3.40	3.0	2,641	$ 2.81

(d) Stock-based compensation:

The Company accounts for its stock-based compensation using the fair value method for all stock options granted since January 1, 2002. For the year ended December 31, 2006, Delphi recorded non-cash compensation expense of $2.5 million. The Company capitalized $0.9 million (December 31, 2005 - $nil) of stock-based compensation directly related to exploration and development activities.

During the year ended December 31, 2006 the Company granted 1.8 million options. The fair values of all options granted during the period are estimated at the date of grant using the Black-Scholes option pricing model. The weighted average fair value of options granted during the period was $2.17 per share (2005 - $1.62). The assumptions used in the Black-Scholes model to determine fair value were as follows:

For the years ended December 31	*2006*	*2005*
Risk free interest rate (%)	*5.0*	*4.5*
Expected life (years)	*5.0*	*5.0*
Expected volatility (%)	*45.0*	*48.0*

(e) Contributed surplus:

The following table outlines the changes in the contributed surplus balance:

As at December 31		*2006*		*2005*
Balance, beginning of year	$	*2,380*	$	*1,072*
Stock-based compensation costs		*3,392*		*1,631*
Reclassification to common shares on exercise		*(145)*		*(323)*
Balance, end of year	$	*5,627*	$	*2,380*

(f) Earnings per share:

Net earnings per share has been based on the following weighted average common shares:

For the years ended December 31	*2006*	*2005*
Basic	*58,051*	*50,060*
Diluted	*58,845*	*50,931*

The reconciling item between the basic and diluted weighted average common shares outstanding is stock options.

note 8: taxes

(a) Expected tax rate:

The provision for income taxes in the financial statements differs from the result that would have been obtained by applying the combined federal and provincial tax rates to the Company's earnings before taxes.

The difference results from the following items:

For the years ended December 31		*2006*		*2005*
Earnings before income taxes	$	*7,689*	$	*11,092*
Statutory tax rate		*34.74%*		*37.67%*
Expected income tax expense		*2,671*		*4,187*
Crown charges		*126*		*3,833*
Resource allowance		*(4)*		*(3,219)*
Alberta royalty tax credit		*(74)*		*(103)*
Stock-based compensation		*865*		*615*
Attributed Canadian Royalty Income ("ACRI")		*(226)*		*(322)*
Rate reduction		*(3,019)*		*(187)*
Other		*447*		*(639)*
Capital taxes		–		*250*
Total taxes	$	*786*	$	*4,415*

(b) Future tax liability:

The tax effect of temporary differences that give rise to significant portions of the future tax assets and liabilities at December 31, 2006 and 2005 are presented below:

As at December 31	2006	2005
Future income tax assets:		
Asset retirement obligations	$ 2,385	$ 2,486
ACRI	367	322
Risk management liability	–	230
Share issue costs	1,569	1,899
e income tax liabilities:		
Risk management asset	(121)	–
operty, plant and equipment	(27,976)	(19,229)
income tax liability	$ (23,776)	$ (14,292)

9: financial instruments

value of financial instruments:

pany's exposure under its financial instruments is limited to financial assets and liabilities, all of which are included in these tatements. The fair values of financial assets and liabilities that are included in the balance sheet approximate their carrying

all of the Company's accounts receivable are with customers and joint venture partners in the oil and gas industry and normal industry credit risks. With respect to counterparties to financial instruments, the Company partially mitigates dit risk by limiting transactions to counterparties with investment grade credit ratings.

ency exchange risk:

s exposed to foreign currency fluctuations as crude oil and natural gas prices are referenced to U.S. dollar denominated

isk:

s exposed to interest rate risk to the extent that bank debt is at a floating rate of interest.

ommodity price risk management:

Company has a price risk management program whereby the commodity price associated with a portion of its future production is fixed. The Company sells forward a portion of its future production and enters into a combination of fixed price sale contracts with customers and commodity swap agreements with financial counterparties. The forward contracts are subject to market risk from fluctuating commodity prices and exchange rates.

As at December 31, 2006, the Company has fixed the price applicable to future production through the following contracts:

Time Period	*Commodity*	*Type of Contract*	*Quantity Contracted*	*Canadian Price (CDN$/unit)*
November 2006 – March 2007	*Natural Gas*	*Physical*	*2,000 GJ/d*	*$10.00 fixed*
November 2006 – March 2007	*Natural Gas*	*Physical*	*4,000 GJ/d*	*$9.50 floor/$10.65 ceiling*
November 2006 – March 2007	*Natural Gas*	*Physical*	*2,000 GJ/d*	*$9.50 floor/$11.35 ceiling*
November 2006 – March 2007	*Natural Gas*	*Physical*	*4,000 GJ/d*	*$8.75 floor/$10.00 ceiling*
November 2006 – March 2007	*Natural Gas*	*Physical*	*2,000 mmbtu/d*	*$11.05 floor/$12.92 ceiling*
January 2007 – March 2007	*Natural Gas*	*Financial*	*2,000 GJ/d*	*$6.50 floor/$10.45 ceiling*
April 2007 – October 2007	*Natural Gas*	*Physical*	*3,000 GJ/d*	*$8.75 floor/$9.55 ceiling*
April 2007 – October 2007	*Natural Gas*	*Physical*	*4,000 GJ/d*	*$8.00 floor/$8.92 ceiling*
April 2007 – October 2007	*Natural Gas*	*Physical*	*2,000 mmbtu/d*	*$8.94 fixed*
April 2007 – October 2007	*Natural Gas*	*Physical*	*2,000 GJ/d*	*$6.50 floor/$8.15 ceiling*
April 2007 – October 2007	*Natural Gas*	*Financial*	*2,000 GJ/d*	*$6.50 floor/$9.00 ceiling*
November 2007 – December 2007	*Natural Gas*	*Financial*	*2,000 GJ/d*	*$6.50 floor/$10.45 ceiling*
November 2007 – March 2008	*Natural Gas*	*Physical*	*3,000 GJ/d*	*$9.00 floor/$9.98 ceiling*
November 2007 – March 2008	*Natural Gas*	*Physical*	*2,000 mmbtu/d*	*$11.07 fixed*
November 2007 – March 2008	*Natural Gas*	*Physical*	*2,000 GJ/d*	*$7.75 floor/$9.03 ceiling*
April 2008 – October 2008	*Natural Gas*	*Physical*	*4,000 GJ/d*	*$7.21 fixed*

note 10: contractual obligations and commitments

The Company is committed, under contracts of varying lengths, for the utilization of gathering, processing and pipeline capacity on a major natural gas processing and gathering system in North East British Columbia. The future minimum commitments are as follows:

2007	*$*	*3,898*
2008		*3,190*
2009		*2,992*
2010		*3,241*
2011		*2,535*
2012 – 2015	*$*	*6,995*

note 11: changes in non-cash working capital items

For the years ended December 31		*2006*		*2005*
Change in working capital item:				
Accounts receivable	$	1,810	$	(12,232)
Prepaid expenses and deposits		9,710		(9,872)
Accounts payable and accrued liabilities		(26,260)		35,013
Total change in non-cash working capital	$	(14,740)	$	12,909
Relating to:				
Operating activities		3,102		3,167
Financing activities		–		–
Investing activities		(17,842)		9,742
	$	(14,740)	$	12,909

note 12: reclassification

Certain amounts have been reclassified to conform to the presentation in 2006.

note 13: subsequent event

On March 1, 2007, the Company issued 7.35 million flow-through common shares at a price of $2.45 per share for gross proceeds of $18.0 million.

corporate information

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Lamont C. Tolley [1]
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